BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-184-E

IN RE:
South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Dominion Energy South Carolina, Incorporated's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A)

PROPOSED ORDER

ON BEHALF OF

DOMINION ENERGY SOUTH CAROLINA, INC.

TABLE OF CONTENTS

INTRODUCTION

This matter comes before the Public Service Commission of South Carolina ("Commission") pursuant to the requirements of S.C. Code Ann. § 58-41-20 as contained in 2019 Act No. 62 ("Act No. 62"), which was enacted into law by the South Carolina General Assembly and became effective on May 16, 2019. Specifically, Act No. 62 directed the Commission to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section." S.C. Code Ann. § 58-41-20(A).

In compliance with Act No. 62, on May 30, 2019, the Commission established the above-captioned docket for the purpose of establishing Dominion Energy South Carolina, Inc.'s ("DESC" or the "Company") standard offer, avoided cost methodologies, form contract power purchase agreements ("PPAs"), commitment to sell forms, and any other terms or conditions necessary to implement the requirements of S.C. Code Ann. § 58-41-20.

I. NOTICE AND INTERVENTIONS

By letter dated July 18, 2019, the Clerk's Office of the Commission instructed the Company to publish, by July 29, 2019, a Notice of Filing and Hearing and Prefile Deadlines ("Notice") in newspapers of general circulation in the area affected by the issues presented in this proceeding. Among other things, the Notice[1] informed customers and the public of the nature of the proceeding and advised all interested parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. On August 5, 2019, the Company filed with the Commission affidavits demonstrating that the Notice was duly published in accordance with the instructions set forth in the Clerk's Office July 18, 2019 letter.

[1] *See* Notice of Filing and Hearing and Prefile Testimony Deadlines dated July 18, 2019.

Timely petitions to intervene were received from Johnson Development Associates, Inc. ("JDA"); the South Carolina Solar Business Alliance, Inc. ("SCSBA"); the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy (collectively, "CCL/SACE"); Walmart, Inc. ("Walmart"); the South Carolina Energy Users Committee ("SCEUC"); and Ecoplexus, Inc. ("Ecoplexus"). DESC did not oppose the petitions to intervene and no other parties sought to intervene in this proceeding. The South Carolina Office of Regulatory Staff ("ORS") also is a party of record pursuant to S.C. Code Ann. § 58-4-10(B).

II. PREHEARING MATTERS

On June 14, 2019, the Commission held an Advisory Committee Meeting to discuss Act No. 62 and related procedural and scheduling issues. On July 17, 2019, the Commission held a hearing to consider oral arguments regarding procedural scheduling issues in this matter including, among other things, whether to consolidate the issues in this matter with those of Docket Nos. 2019-185-E and 2019-186-E pertaining to Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. In Order No. 2019-524, the Commission concluded that judicial economy would not be served in consolidating these three dockets[2] and established prefiled testimony deadlines and hearing dates for the individual dockets.[3] The Commission concluded that the proposed schedule would best effectuate the statutory requirements of Act No. 62 and would afford all parties the opportunity to litigate their positions on the matters before the Commission.

On August 12 and 19, 2019, the Commission held two Special Commission Business Meetings, during which the Commission received presentations from and conducted public

[2] On May 23, 2019, the Commission staff also opened a generic docket, Docket No. 2019-176-E, to establish each electrical utility's standard offer, avoided cost methodologies, form contract PPAs, commitment to sell forms, and any other terms and conditions necessary to implement S.C. Code Ann. § 58-41-20. By way of Order No. 2019-524, the Commission closed Docket No. 2019-176-E.

[3] *See also* Notice of Filing and Hearing and Prefile Testimony Deadlines dated July 18, 2019.

interviews of prospective third-party consultants and experts who sought to be employed to perform the duties of a qualified independent third party as set forth in S.C. Code Ann. § 58-41-20(I). The Commission also permitted the parties of record to submit proposed written questions concerning each of the proposed candidates. *See* Order No. 2019-557, dated August 7, 2019. By way of Order No. 2019-585, dated August 21, 2019, the Commission also permitted the parties of record to submit comments on the public interviews of the prospective third-party consultants by August 23, 2019. On August 28, 2019, the Commission issued Order No. 2019-621, in which it selected John Dalton of Power Advisory, LLC to serve as the qualified independent third party in Docket No. 2019-184-E.

On August 23, 2019, and in accordance with the Notice issued by the Commission Staff on July 18, 2019, DESC prefiled the direct testimony and exhibits of its witnesses.[4] On September 23, 2019,[5] the other parties of record likewise prefiled the responsive direct testimony and exhibits of their witnesses. On October 7, 2019, the Company prefiled the rebuttal testimony and exhibits of its witnesses and, on October 11, 2019, the other parties of record prefiled surrebuttal testimony and exhibits of their witnesses.[6]

On September 13, 2019, the Hearing Examiner in this matter issued a directive permitting any party to this docket to file a prehearing brief by September 23, 2019, and a responsive brief by September 30, 2019. *See* Order No. 2019-103-H. Subsequently, the Hearing Officer revised the

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[4] On September 20, 2019, the Company filed amended versions of the direct testimony of Witnesses James W. Neely, John E. Folsom, Jr., and Allen W. Rooks to correct certain inadvertent errors that were contained in the versions of testimony filed on August 23, 2019.

[5] On September 17, 2019, the Hearing Officer issued a directive, Order No. 2019-106-H, granting ORS's request for an extension until September 23, 2019, for the other parties of record to prefile responsive direct testimony of their witnesses. Likewise, DESC's time to prefile rebuttal testimony and exhibits was extended to Monday, October 7, 2019.

[6] On October 12, 2019, SCSBA filed amended versions of the surrebuttal testimony of Witnesses Burgess and Levitas.

prehearing briefing schedule to allow the parties until September 30, 2019, to file a prehearing brief and until October 8, 2019 to file a responsive brief. *See* Order No. 2019-108-H. On September 30, 2019, DESC, ORS, and CCL/SACE each filed a prehearing brief and SCSBA and JDA filed a joint prehearing brief. Walmart and SCEUC also separately filed letters in lieu of a prehearing brief. On October 8, 2019, DESC and CCL/SACE each filed a responsive prehearing brief and SCSBA and JDA jointly filed a letter in lieu of a responsive prehearing brief.

III. HEARING

In order to hear testimony, receive documentary evidence, and consider the merits of this case, the Commission convened a hearing on this matter on October 14-15, 2019, with the Honorable Comer H. "Randy" Randall presiding. DESC was represented by K. Chad Burgess, Esquire; Matthew W. Gissendanner, Esquire; Belton T. Zeigler, Esquire; and Mitchell Willoughby, Esquire. JDA and SCSBA were jointly represented by Weston Adams, III, Esquire and Jeremy C. Hodges, Esquire. JDA also was represented by James H. Goldin, Esquire and SCSBA also was represented by Benjamin L. Snowden, Esquire. Richard L. Whitt, Esquire, jointly represented SCSBA and Ecoplexus. CCL/SACE was represented by Stinson Woodward Ferguson, Esquire; J. Blanding Holman, IV, Esquire; and Lauren Joy Bowen, Esquire. Scott Elliott, Esquire, represented SCEUC. ORS was represented by Jeffrey M. Nelson, Esquire; Nanette S. Edwards, Esquire; and Jenny R. Pittman, Esquire. In this Order, DESC, JDA, SCSBA, Ecoplexus, CCL/SACE, SCEUC, and ORS are collectively referred to as the "Parties" or sometimes individually as a "Party."

DESC presented the direct testimony of John H. Raftery and the direct testimonies and exhibits of Dr. Joseph M. Lynch, James W. Neely, Eric H. Bell, Dr. Matthew W. Tanner, Daniel

F. Kassis,[7] and Allen W. Rooks. SCSBA presented the responsive direct testimonies of Hamilton Davis and Jon Downey and the responsive direct testimonies and exhibits of Steven J. Levitas and Ed Burgess. JDA presented the responsive direct testimony of Rebecca Chilton. CCL/SACE presented the responsive direct testimony and exhibits of Derek P. Stenclik. ORS presented the responsive direct testimony of Robert A. Lawyer and the responsive direct testimony and exhibits of Brian Horii.[8]

In response to the issues raised in the responsive direct testimony presented by the other parties, DESC presented the rebuttal testimony of Witnesses Lynch, Tanner, Bell, Neely, Raftery, and Hanzlik. DESC also presented the rebuttal testimony and exhibits of Witnesses Kassis and Rooks.

SCSBA presented the surrebuttal testimony of Witnesses Levitas, Burgess, and Davis. JDA presented the surrebuttal testimony of Witness Chilton. CCL/SACE presented the surrebuttal testimony of Witness Stenclik. ORS presented the surrebuttal testimony of Witnesses Horii and Lawyer.

IV. STATUTORY STANDARDS AND REQUIRED FINDINGS OF FACT[9]

A. Background of Act No. 62 and PURPA

As an initial matter, the Commission finds that it is important to address the disputes raised regarding the underlying purpose of Act No. 62, the requirements of the Public Utility Regulatory

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[7] At the hearing, Mr. Kassis testified that he had read Mr. Folsom's pre-filed direct testimony and exhibits and was adopting the pre-filed direct testimony and exhibits of Mr. Folsom.

[8] Without objection, the Commission permitted the parties to utilize panels for the presentation of witnesses. DESC Witnesses Kassis and Raftery were presented in the first panel for the Company; DESC Witnesses Hanzlik and Bell were presented in the second panel; and DESC Witnesses Neely, Tanner, and Lynch were presented in the third panel. DESC Witness Rooks separately presented his testimony. SCSBA Witness Levitas and JDA Witness Chilton were presented in the next panel. SCSBA Witnesses Downey, Davis, and Burgess were presented in the next panel. CCL/SACE Witness Stenclik and ORS Witness Lawyer separately presented their testimonies. Without objection, ORS Witness Horii also separately presented his testimony via video teleconferencing.

[9] To the extent the following findings of fact are conclusions of law, they are adopted as such.

Policies Act of 1978 ("PURPA"), including the Federal Energy Regulatory Commission's ("FERC") implementing regulations and orders, and the effect these state and federal statutes have on the issues presented in this matter.

Regarding Act No. 62, the testimony of the various witnesses to this proceeding are at odds with respect to the intent of the General Assembly in passing this piece of legislation. For example, SCSBA Witness Davis testified that Act No. 62 "recognizes and prioritizes increased competition and consumer choice within the state's electricity marketplace." Tr. at 544.4. Mr. Davis also suggested that Act No. 62 encourages "an approach to regulatory oversight that prioritizes the expansion of renewable energy, consumer choice and protection, and increased competition from small power producers." Tr. at 544.6. Similarly, JDA Witness Chilton testified that PURPA and Act No. 62 require that Qualifying Facilities ("QFs") "be allowed to compete on even terms with the utility's other generation resources, both present and projected" and that they "implicitly require[] that the QF be able to obtain regularly-available, market-rate financing for the costs of developing, building, and operating their projects." Tr.at 462.4.

The Commission recognizes that Act No. 62 has made significant changes to the procedures related to avoided costs and utility purchases of power under PURPA and the issues to be considered by the Commission in this docket. However, a fundamental question posed to the Commission has remained unchanged: whether or not the avoided costs paid to QFs by electric utilities and the related agreements between such entities are reasonable, appropriate, and in compliance with applicable laws. In fact, in enacting Act No. 62, the General Assembly made clear that any decisions by this Commission must "be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and [FERC's] implementing regulations and orders, and nondiscriminatory." S.C. Code Ann. § 58-41-20(A). These requirements are echoed in the testimony of Mr. Davis who recognized that the Commission's "decisions on avoided cost issues must be 'consistent with PURPA and [FERC's] implementing regulations and orders,' and that any power purchase agreements or other terms and conditions for [QFs] are commercially reasonable and consistent with PURPA and FERC's implementing regulations and orders." Tr. at 544.6-544.7.

The General Assembly, through Act No. 62, encouraged the development of renewable energy resources, such as solar generation, in a manner that is fair and balanced to all customers of all programs related to renewable energy and energy storage. But it also made clear that revenue recovery, cost allocation, and rate design of utilities should be just and reasonable, and it established procedures to ensure that QFs are properly compensated for the energy they produce, as is required by PURPA, while at the same time mandating that costs not be shifted onto utility customers in an effort to subsidize such programs. *See* S.C. Code Ann. § 58-41-05 (renewable energy issues must be addressed "in a fair and balanced manner, considering the costs and benefits to all customers" and must ensure that "the revenue recovery, cost allocation, and rate design of utilities that [the Commission] regulates are just and reasonable"); S.C. Code Ann. § 58-41-20(A) (the Commission "shall strive to reduce the risk placed on the using and consuming public"). In this regard, Act No. 62 is designed to ensure that the Company determines its costs and sets its rates at just and reasonable levels to comply with the legislative requirements and to implement the programs required by the Act, while also preventing the unfair and unnecessary shifting of costs to customers.

With respect to avoided costs, the Commission also recognizes that Act No. 62 requires the establishment of methodologies for each electric utility that accurately determines the costs the utility avoids as a result of purchases it makes from QFs under PURPA. *See* S.C. Code Ann. § 58-

41-20(B)(3). PURPA specifically provides that "[n]o … rule … [regarding the sale and purchase of QF power] shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy." 16 U.S.C.A. § 824a-3(b). PURPA's implementing regulations also expressly provide that "[n]othing … requires any electric utility to pay more than the avoided costs for purchases" from QFs. 18 C.F.R. § 292.304(a)(2). Similarly, by setting a ceiling of incremental cost on the amount a utility should be required to pay for a QF's power, Congress expressed that PURPA is "not intended to require the rate payers of a utility to subsidize cogenerators or small power products." Joint Conference Committee Report, H.R.Rep. No. 95-1750 at 98, 1978 U.S.C.C.A.N. 7797, 7832.

Unlike the suggestions made by SCSBA, JDA, and CCL/SACE, Act No. 62 therefore does not establish and is not designed to provide additional benefits or incentives for solar generating facilities, other than the payment of the utility's avoided costs, which is what is required by PURPA. Instead, the goal of Act No. 62 is to ensure that QFs are properly paid for the electricity they produce in accordance with the costs avoided by utilities while also making sure that excess costs are not shifted to or borne by utility customers. In this manner, purchases from QFs are revenue neutral to the ratepayers, which is what is required by both PURPA and Act No. 62.

For these reasons, the Commission concludes that it is important to calculate a utility's avoided costs correctly so that customers will not be impacted by, and will be economically indifferent to, purchases of QF power as opposed to paying for DESC's cost to construct and operate additions to utility power plant or to purchase power. Likewise, ensuring that avoided costs are correctly calculated will allow QFs, such as solar generators, to secure a non-discriminatory rate to which they are entitled. To approve a methodology that results in a rate that exceeds the utility's avoided costs would require customers to improperly subsidize privately-held QF projects, which would be at odds with the specific, statutory requirements established by the General Assembly in Act No. 62. *See* S.C. Code Ann. § 58-41-20(A).

B. Requirements of S.C. Code Ann. § 58-41-20

Among other things, Act No. 62 requires the Commission to establish "each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement" the requirements of S.C. Code Ann. § 58-41-20.

1. Avoided Cost Methodology

As defined by both PURPA regulations and Act No. 62, "avoided costs" are "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from [QFs], such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6); S.C. Code Ann. § 58-41-10(2). FERC further recognizes that avoided costs include two components: "energy" and "capacity." Specifically, "[e]nergy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel and some operating and maintenance expenses.[10] Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) ("Order No. 69"). The Commission also has recognized in Order No. 81-214, dated March 20, 1981, Docket No. 80-251-E, and in subsequent decisions

[10] The Commission also has recognized that energy costs include certain environmental costs which are subject to recovery in fuel rates pursuant to S.C. Code Ann. § 58-27-865.

that electric utilities are entitled to recover from customers their avoided costs paid to QFs under PURPA.

Importantly, PURPA does not require electric utilities to pay QFs more than their avoided costs. To the contrary, PURPA and its implementing regulations expressly provide that "[n]othing … requires any electric utility to pay more than the avoided costs for purchases" from QFs. 18 C.F.R. § 292.304(a)(2). Similarly, by setting a ceiling of incremental costs on the amount a utility should be required to pay for a QF's power, Congress expressed that PURPA is "not intended to require the rate payers of a utility to subsidize cogenerators or small power products." H.R. Rep. No. 95–1750, at 98. For these reasons, PURPA is intended to equalize the rates charged for utility power resource additions and utility purchases of QF power so as to make certain that customers do not pay more for electricity under either option.

In like manner, Act No. 62 does not provide or allow the Commission to provide benefits or incentives for solar generating facilities, beyond the payment of the utility's avoided costs as objectively established. To the contrary, S.C. Code Ann. § 58-41-20(A) provides that "[a]ny decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility … and shall strive to reduce the risk placed on the using and consuming public." Thus, if a utility's avoided costs are calculated reasonably to reflect the utility's avoided costs, customers would not be impacted by purchases of QF power, and would be economically indifferent to whether the power in question was supplied by the QF purchase or by other means. Under both PURPA and Act No. 62, utilities are only required to pay QFs the utility's avoided costs, and nothing more. To do otherwise would be in direct contravention of the requirements set forth in S.C. Code Ann. § 58-41-20(A) because it would require customers to improperly subsidize these privately held QF projects, including privately owned solar generating facilities.

In considering the avoided cost methodologies to be approved in this proceeding, S.C. Code Ann. § 58-41-20(B) requires the Commission to "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:

> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs; … and
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> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."

2. Standard Offer

A standard offer (the "Standard Offer") is defined by S.C. Code Ann. § 58-41-10(15) to mean "the avoided cost rates, power purchase agreement,[11] and terms and conditions approved by the commission and applicable to purchases of energy and capacity by electrical utilities … from small power producers up to two megawatts AC in size." Stated differently, a Standard Offer is a PPA that contains an avoided cost rate paid to eligible QFs that are 2 MW in size or smaller. Additionally, the Standard Offer contract sets the terms and conditions and allows any qualifying small power producer, as defined by S.C. Code Ann. § 58-41-10(14), to contract with the utility to supply electricity at established rates without the need to negotiate individual contracts. The Standard Offer therefore establishes set prices, terms, and conditions, and is not negotiated by DESC or the eligible QF. It is intended to address the concern that the costs of negotiating and administering individually-negotiated contracts could render smaller projects non-viable. In this

[11] "'Power purchase agreement' means an agreement between an electrical utility and a small power producer for the purchase and sale of energy, capacity, and ancillary services from the small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-10(9).

manner, Act No. 62 expands the requirements of PURPA, which only requires that utilities have in place standard rates for QFs up to 100 kW-AC, by increasing the upper limit on the required offer of standardized rates, terms, and conditions contained in PURPA from 100 kW-AC to 2 MW-AC in size, a 20-fold increase. An increase of this magnitude in the availability of Standard Offer contracts accentuates the importance of ensuring that their pricing, terms and conditions do not prejudice the interests of customers. Consistent with the express requirements of Act No. 62, the Commission must ensure that the terms of these Standard Offer contracts do not unintentionally or unexpectedly result in the shifting of costs onto ratepayers, or result in operational issues for the electric utility systems on which customers depend which themselves may be difficult or expensive to resolve.

3. Form Contract PPA

A form contract PPA is similar to a Standard Offer, except that, pursuant to S.C. Code Ann. § 58-41-20(A), it is for use for qualifying small power production facilities that are not eligible for the Standard Offer, i.e., QF facilities that are greater than 2 MW and up to 80 MW in size. The statute also requires that these PPAs contain provisions for force majeure, indemnification, choice of venue, confidentiality provisions, and other such terms. However, the PPA is not determinative of the price or duration of the contract. These issues are to be separately negotiated by the Company and the applicable QF and "may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-20(B)(3). As proposed by DESC, the terms and conditions for the Standard Offer and the form PPA are similar since the potential impacts to the Company's system and its customers from projects 2 MW or less in size can be comparable to those that exceed 2 MW.

4. Commitment to Sell Form

Act No. 62 also mandates that QFs "have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility." S.C. Code Ann. § 58-41-20(D). This standard notice of commitment to sell form ("NOC Form") is required to provide the QF a reasonable period of time from its submittal of the form to execute a PPA, but shall not require a QF, "as a condition of preserving the pricing and terms and conditions established by its submittal of an executed [NOC Form] to the electrical utility, … to execute a [PPA] prior to receipt of a final interconnection agreement from the electrical utility." *Id.*

C. Issues Related to Bifurcation of Docket No. 2019-2-E

In addition to the issues required to be addressed in this proceeding under S.C. Code Ann. § 58-41-20, it also is appropriate and necessary for the Commission to address certain issues that previously were presented for consideration in the Company's 2019 fuel cost proceeding, Docket No. 2019-2-E, but ultimately bifurcated from the decisions reached in that matter. Specifically, prior to the enactment of Act No. 62, DESC's avoided costs and underlying methodologies were approved in the Company's annual fuel cost proceeding as provided by S.C. Code Ann. § 58-27-865. As part of the Company's 2019 fuel cost proceeding, DESC proposed to include the updated avoided costs, variable integration costs, and updates to the Net Energy Metering ("NEM") values in its fuel costs effective with the first billing cycle of May 2019. However, the Commission determined that these issues should be bifurcated from consideration in Docket No. 2019-2-E and would be addressed in a later, appropriate hearing. Order No. 2019-229 at 1; Order No. 2019-43-H at 1. The Commission also determined that DESC's then-current avoided cost rates and NEM values were to remain the same as those in effect at the time the issues were bifurcated and that, after the Commission held a hearing to consider updates to these rates, these rates and values would be subject to a "true up." Order No. 2019-43-H at 1. Accordingly, these issues are appropriate for consideration in the above-captioned docket.

V. EVIDENCE OF RECORD AND RESULTING FINDINGS OF FACT[12]

A. Report of Power Advisory, LLC

Prior to reaching the central determinations in this case, the Commission must address the "Independent Third Party Consultant Final Report Pursuant to South Carolina Act 62" which was submitted by Power Advisory, LLC on November 4, 2019 (the "Power Advisory Report"). As noted above, the Commission retained Power Advisory to serve as "a qualified independent third party" in these proceedings, as such is contemplated by S.C. Code Ann. § 58-41-20(I). Under that statute, the Commission is required to engage such a third party, whose responsibility it is "to submit a report that includes the third party's independently derived conclusions as to that third party's opinion of each utility's calculation of avoided costs." § 58-41-20(I). The Commission may then use the third-party's report "along with all other evidence submitted during the proceeding to inform its ultimate decision setting the avoided costs for each utility." *Id.*

After the Power Advisory Report was submitted, on November 8, 2019, DESC timely submitted its Comments in Response to the Power Advisory, LLC Report, and at the same time filed a Motion to Strike Final Report of Power Advisory, LLC. Both the Comments and the Motion submitted by DESC point out that § 58-41-20(I) requires the independent third party to reach "independently derived conclusions" regarding the appropriate calculation of avoided costs, and that the Power Advisory Report failed in this regard because, rather than perform an independent

[12] As to all factual matters, they reflect the Commission's decision that the preponderance of the evidence as presented in this hearing, and after weighing the probative value and credibility of the testimony of each witness, supports the conclusion reached. To the extent the following findings of fact are conclusions of law, they are adopted as such.

analysis or study of DESC's avoided costs, the Power Advisory Report simply summarized the testimony of the parties in this case, and then, for each topic that it addressed, selected the position with which it most agreed. DESC argues that this was not the task that Power Advisory was hired to perform, that Power Advisory, by its Report, has essentially sought to take on this Commission's decision-making role in these proceedings, and that the Power Advisory Report therefore ought to be disregarded by the Commission and stricken from the record.

After careful review of Act No. 62, and particularly § 58-41-20(I), the Commission concludes that the Power Advisory Report does not meet the requirements of the Act. While the Commission appreciates the work that Power Advisory performed in this case, Act No. 62 contemplates the retention of a qualified third party for the specific purpose of reaching "independently derived conclusions" regarding a utility's avoided costs. Power Advisory was hired in this case to perform its own independent analysis and study regarding the appropriate calculation of DESC's avoided costs, which this Commission could then review and consider in reaching its final determinations in this case. However, as is evident from the Power Advisory Report itself, no such independent study or analysis was conducted. Instead, the Power Advisory Report simply recounts the testimony offered by each party and then essentially "finds" in favor of one of the positions asserted. As DESC observed, it is the province of this Commission to make "findings and conclusions, and the reasons or bases therefor, upon all the material issues of fact or law presented in the record." S.C. Code Ann. § 58-3-250(A). In the absence of an independent study or analysis of the kind contemplated in § 58-41-20(I), the Commission simply cannot use the information contained in the Power Advisory Report, nor can the Commission rely upon the Power Advisory Report as proxy in its responsibility to make findings of fact and conclusions of law in this case.[13] The Commission therefore grants DESC's Motion to Strike. The Power Advisory Report is stricken from the record in this case, and the Commission will not rely upon it in these proceedings.

B. Avoided Cost Methodologies

1. Difference in Revenue Requirements Methodology

DESC proposes in this proceeding to use a Difference in Revenue Requirements ("DRR") methodology to calculate both the energy component and the capacity component of its avoided costs. Tr. at 308.7-308.8. The DRR methodology is one of the generally accepted methods for calculating PURPA avoided energy costs, is used throughout the United States, and has been previously approved by the Commission in Order Nos. 2016-297 and 2018-322(A). Tr. at 695.25. This approach involves calculating the revenue requirements between a base case and a change case. Tr. at 308.8. The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed PPAs. *Id.* The change case is the same as the base case except that a zero-cost purchase transaction is modeled after assuming the addition of an incremental amount of QF energy to its system. *Id.* The Company's change case also reflects an increase in the amount of operating reserves maintained by DESC to address the variable nature of solar energy. *Id.* For the avoided energy cost determination, the Company uses a carefully constructed computer program called PROSYM, which models the commitment and dispatch of generating units to serve load hour by hour, makes two runs and estimates the production costs and benefits that result from the

[13] The Commission notes that § 58-41-20(I) and prohibitions on *ex parte* communications limit the contact that the Commission is allowed to have with Power Advisory. Thus, after Power Advisory was hired to perform the statutory task required of a qualified independent third party, the Commission has had no communications with Power Advisory about the merits of this case, and was unable to provide direction or guidance to Power Advisory as it performed its work. The Commission is now aware that Power Advisory misconstrued its role in these proceedings, and the assignment that it was hired to perform.

purchase transaction. *Id.* The base and change cases are identical except for the zero-cost purchase transaction and, in the change case for solar, the increased operating reserves. *Id.* The avoided energy cost is the difference between the base case costs and the change case costs. *Id.*

For avoided capacity costs, DESC calculates the difference in revenue requirement between the base case and the change case. Tr. at 308.11. Using the resource plan in its latest integrated resource plan ("IRP") or an updated resource plan, if appropriate, DESC calculates the incremental capital investment-related revenue required to support the existing resource plan. *Id.* For the calculation of avoided capacity costs, DESC derives a change case in its resource plan by considering the impact of adding incremental QF capacity. Tr. at 308.11 – 308.12. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. Tr. at 308.12.

Although the other parties of record raised concerns with certain inputs and assumptions used in connection with the DRR methodology, which will be addressed further below, no other party proposed an alternative methodology to calculate DESC's avoided costs or objected to the use of the DRR methodology. The Commission therefore finds that it is appropriate to use the DRR methodology to calculate the Company's avoided costs.

2. Incremental Change Amount

As part of the DRR methodology, DESC proposes to calculate its avoided energy and capacity costs based upon an assumed incremental addition of 100 MW of QF energy. Tr. at 308.8. ORS, however, proposes to calculate the avoided costs based upon an assumed addition of 93 MW of QF energy based upon the capacity of combustion turbine ("CT") units that DESC projects to add for new capacity in its IRP. Tr. at 695.39. ORS also suggests that it is appropriate to use a 93 MW change because of the "lumpiness," or limited flexibility of sizing of CT plants. *Id.* No other party of record proposed that a different capacity addition should be used in connection with the DRR methodology.

The Commission finds that it is appropriate for DESC to use a 100 MW change in energy in connection with its DRR methodology. Primarily, PURPA specifically provides that a utility may use a change of up to 100 MW to calculate avoided energy costs, 18 C.F.R. § 292.302(b)(1), and Act No. 62 specifies that the Commission's decisions in this proceeding shall be consistent with PURPA and FERC's implementing regulations and orders. S.C. Code Ann. § 58-41-20(A). In addition, the Commission finds that ORS's concerns about the "lumpiness" of a 100 MW addition are without merit. The record reflects that the only way to avoid such "lumpiness" would be to add additional resources that exactly equal the amount needed to meet the reserve margin requirement each year, which would be unreasonable and inappropriate for planning purposes. The Commission therefore finds that the use of a 100 MW change in QF capacity is reasonable, appropriate, and consistent with Act No. 62, PURPA, and FERC's implementing regulations and orders.

3. Avoided Energy Costs – Time Periods

Using the DRR methodology, DESC proposes to calculate its avoided energy costs over two time periods. Tr. at 308.8 – 308.9. The short-run avoided energy costs, which are reflected in Rate PR-1 and which apply to small QFs of not more than 100 kilowatts ("kW"), are calculated for a 12-month period. Tr. at 308.8. For solar QFs that have production capacity up to 2 megawatts ("MW") and that are subject to Rate PR-Standard Offer, and for solar QFs that have production capacity greater than 2 MW and that will sell the energy generated pursuant to an executed PPA, DESC calculates the long-run avoided energy costs for a 10-year period. Tr. at 308.8 – 308.9; 308.11. The Company then divides these ten-year periods into two groups of five years. *Id.* For non-solar QFs subject to Rate PR-1 or Rate PR-Standard Offer, DESC then accumulates the avoided energy costs into four time-of-use periods reflecting the amounts non-solar QFs would be paid based on how much energy they produce in each of the four time-of-use periods. Tr. at 308.11; 308.18.

Although the other parties of record raised concerns with certain inputs and assumptions used in connection with the DRR methodology, which will be addressed further below, only SCSBA addressed any issues with respect to the time periods used by DESC to calculate avoided energy costs. Specifically, SCSBA Witness Burgess expressed a concern that DESC's selection of the four pricing periods was potentially biased against solar QFs on the basis that DESC's proposed avoided energy costs are higher during the winter "Off Peak Season" months and lower during the summer "Peak Season" months when solar resources are more abundant. Tr. at 523.25. As DESC Witness Neely testified, however, the four time-of-use rates are not applicable to solar QFs, but only to non-solar QFs. Tr. at 308.11. Although Witness Burgess testified in surrebuttal that the four time-of-use rates were included in certain modeling information produced by DESC in discovery, Tr. at 527.8, SCSBA failed to demonstrate how this information evidenced bias by DESC in proposing rates for non-solar QFs.

Accordingly, the record reflects that DESC's proposed time periods to calculate avoided energy are reasonable and appropriate and the Commission finds that they should be approved for use in this proceeding.

4. Avoided Energy Costs – Operating Reserves

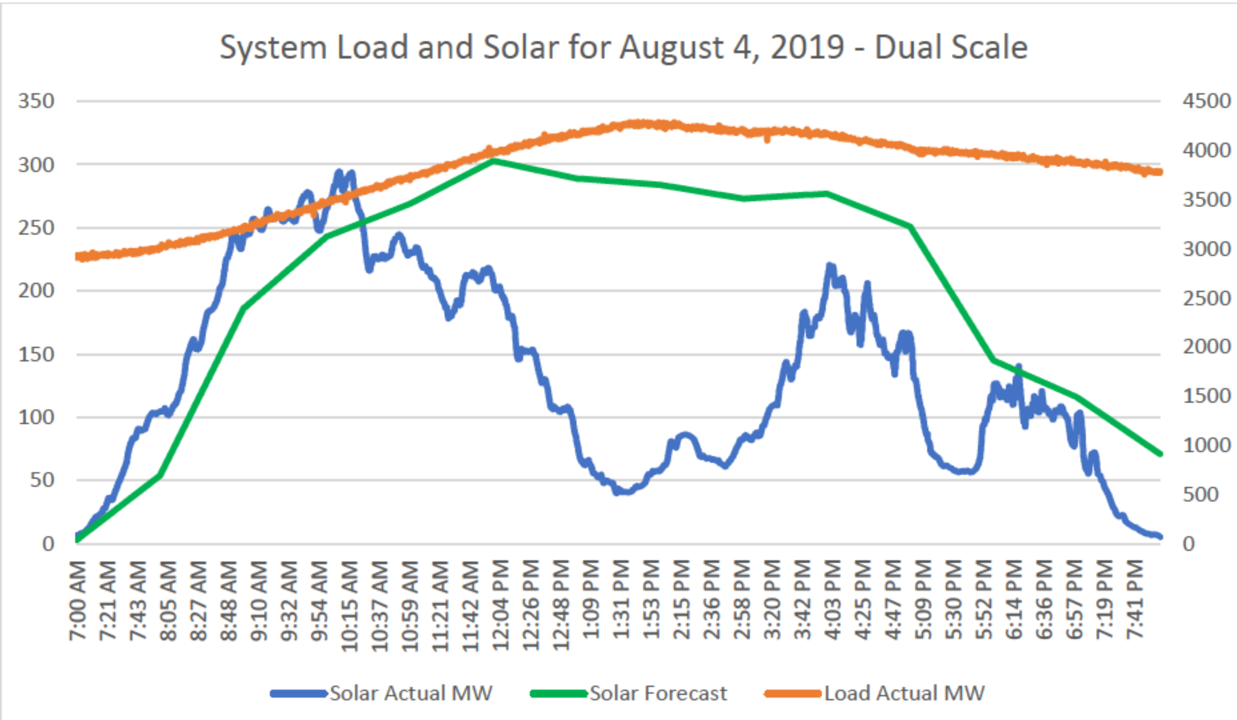
In calculating its avoided energy costs for solar QFs, DESC determined that additional reserves equal to 35% of the installed solar capacity are needed to cover most of the one-hour solar intermittency. Tr. at 308.23. The Company therefore modeled its avoided cost calculations with additional reserves equal to 35% of the installed solar capacity, during solar generating hours, but noted that, as more solar is added to the system, these percentages may change and new operating reserve requirements will be reflected in future avoided cost calculations. Tr. at 308.10.

Carrying additional operating reserves for QF solar intermittency is a widely accepted practice and was not disputed by the intervening parties. In fact, ORS Witness Horii testified that it is reasonable for the Company to require additional operating reserves to address the possibility that renewable generation output will be lower than forecasted and that increasing operating reserves is one method for addressing the uncontrolled variation in solar output. Tr. at 695.11. He also testified DESC derived the 35% value from 2018 solar data by looking at the observed drops in solar output over a 1-hour period and determining that the 35% value would be required to cover 96% of the 1-hour drops in solar output. Tr. at 695.28. However, Witness Horii stated that, if solar output was analyzed over a shorter period of time such as a 15-minute period, the amount of solar drops would be less and the need for additional reserves would be less. *Id.* He also stated that, if there is a drop in expected solar output in subsequent 15-minute periods, the operator could call upon other off-line resources to stand by to inject power to restore the desired operating reserve level. Tr. at 697.2. On this basis, ORS recommended that avoided energy costs should be calculated assuming additional reserves of only between 13% and 18%. Tr. at 697.2 – 697.3.

According to the Company, however, using data analyzed over only a 15-minute period would not accurately reflect the operating reserves required to cover periods of observed solar drops that can last up to 4 hours as solar output often drops periods much longer than 15 minutes. Tr. at 319.6. Company Witness Neely also noted that maintaining additional reserves equal to 35% of installed solar generation only covers 96% of the 1-hour reductions and that even this level of reserves may not be enough to maintain system reliability. *Id.*

In support of the Company's position regarding the importance of maintaining operating reserves, DESC Witness Hanzlik testified that real-time operations of DESC's Balancing Authority require operating reserves to balance DESC's load and generation at all times and after all contingency events in order to maintain system reliability and compliance with the North American Electric Reliability Corporation ("NERC") Resource and Demand Balancing Reliability Standards ("BAL Standards"). Tr. at 188.3. He also stated that operating reserves are calculated daily to ensure the generating capacity is available to balance load and generation as load increases from its minimum level to the maximum peak hour of the day. *Id.* With the addition of solar generation and the intermittent production associated with this resource, however, Witness Hanzlik testified that there is a need for increased operating reserves specific to solar generation to maintain compliance with the BAL Standards. *Id.*

Witness Hanzlik further explained that DESC's operating experience shows that it cannot be reliably predicted when solar panels will either reduce or increase their output, and therefore the Company must factor in the variable and significantly unpredictable operating characteristics of solar generation as a factor effecting reliability. *Id.* As a demonstration of the unpredictable nature of solar generation, Witness Hanzlik provided a graph that illustrated solar variability in DESC's recent experience using actual data. Specifically, and as reflected in the graph below, on August 4, 2019, at 10:00 a.m., solar generation peaked at 293 MW. *Id.* For the next three hours, however, solar output fluctuated while decreasing by over 80 percent to slightly below 50 MW, which was a large divergence from the solar forecast, while DESC's load continued to increase. Tr. at 188.3-4. The graph also shows that, over the next three hours solar generation increased by 300% to 150 MW (as load decreased), before decreasing by the same 300% to 50 MW by late afternoon. Tr. at 188.4. Witness Hanzlik testified that, during this time DESC had to utilize generating units with high ramp rates to provide quick generating responses and maintain reliability. *Id.* He further testified that the issues experienced by DESC on August 4, 2019, as graphically depicted below, shows exactly how and why DESC must maintain Operating Reserves for solar generation and why this need increases as the installed capability of PV Solar increases to 1,048 MW. *Id.*



Given DESC's obligation to provide reliable and safe service even when solar does not provide any energy and given the variability of solar generation demonstrated on the Company's system, the Commission finds that DESC's proposed use of 35% operating reserves is reasonable and appropriate to calculate avoided energy costs in this filing. The record reflects that 15 minutes is too short of a period to assess the impact of solar intermittency on the operations and economics of the electric generating system. *See* Tr. at 176.6. In addition, NERC and FERC standards require DESC to maintain sufficient resources to respond and maintain compliance when a frequency event occurs even if solar output has previously dropped well below forecasted levels. *See id.* The

Commission recognizes the importance of electric utilities providing safe and reliable electric service to its customers, which includes its ability to provide adequate power in the event of a power loss at a generating facility, including a QF. Because the record reflects that energy output from solar QFs can steadily drop over periods longer than 15 minutes, as demonstrated through the testimony of Company Witness Hanzlik and data reflecting actual operating experience, the Commission finds that it is appropriate for DESC to consider 1-hour reductions in solar QF energy when determining its operating reserve needs. Accordingly, the Commission also finds that it is appropriate for DESC to assume operating reserves equal to 35% of the production capability of solar QFs when calculating its avoided energy costs.

5. Avoided Capacity Costs – Impact of Solar on Capacity Needs

A primary issue in this proceeding is what impact energy supplied by solar QFs has on DESC's future capacity needs. In analyzing this issue, DESC Witness Lynch conducted an updated analysis of the study performed as part of the Company's 2018 fuel proceeding, Docket No. 2018-2-E. This analysis, which is presented in a study titled "The Capacity Benefit of Solar QFs 2018 Study ("Solar Capacity Benefit Study"), demonstrates that solar power cannot help serve DESC's winter peaking needs. Tr. at 276.3; Hr'g Ex. 4, JML-1. This is because, in the winter, the Company's system typically peaks early in the morning before sunrise. Tr. at 276.3 – 276.4. In addition, the Solar Capacity Benefit Study demonstrates that, for most non-summer days, the system load peaks either before sunrise or after sunset, again with solar providing little or no support for serving DESC's daily peaks. Tr. at 276.4.

During the summer season, the Solar Capacity Benefit Study concludes that approximately 46% of the solar farm nameplate capacity for the existing 1,048 MW in existing contracts will typically be provided to DESC's system during the summer peak days. *Id.* The 46% rating is based on the average solar output during the five highest summer peak load days. For the balance of summer days, the rating drops to 26%. *Id.* Therefore, in developing a resource plan, DESC will consider 26% of the solar nameplate as a base resource available for the whole summer season with an additional 20% for a total of 46% available on summer peaking days. *Id.* The study also demonstrates that, as more and more solar capacity is added to the system, the time of the system peak net of the solar output is shifted later and later in the day until it reaches the time of sunset, about 8 p.m., after which adding more solar capacity no longer affects the peak. Tr. at 276.6. For this reason, as the amount of solar capacity increases, each increment of solar capacity affects the peak on fewer days and shows that the last 100 MW increment of solar capacity on the system does not impact peak demand on approximately 77% of the days in those seven months. Tr. at 276.5. Witness Lynch testified that the basic reason for this effect is that the time of the net system peak can be changed by solar capacity. Tr. at 276.6. He testified that, particularly in summer, as more and more solar capacity is added to the system, the time of the system peak net of the solar output is shifted later and later in the day until it reaches the time of sunset, after which adding more solar capacity no longer affects the peak. *Id.*

DESC Witness Lynch also considered the Effective Load Carrying Capacity ("ELCC") methodology to establish the firm capacity value of solar, even though he explained that the ELCC value is an application of the Loss of Load Expectation ("LOLE") technique which is not appropriate for DESC. Tr. 276.9. This methodology demonstrates that the addition of 500 MW of solar represents 185 MW of firm capacity, or about 37% of nameplate capacity. Tr. at 276.10. When another 500 MW of solar is added to the system, however, the incremental value of solar decreases to only 59 MW of firm capacity. *Id.* Additionally, Dr. Lynch showed that the ELCC value of an increment of 100 MW of solar above the 1,048 MW of solar under a signed PPA to

DESC, is only 3 or 4 MW, i.e., 3 or 4%. Thus, the 244 MW or 24% of nameplate capacity does not reflect an increment of QF capacity which would be methodologically appropriate but rather reflects the total 1,000 MW of solar nameplate capacity currently under a signed PPA.

However, DESC Witness Lynch also testified that, in the context of determining the Company's avoided costs, "capacity value" means capacity costs that would be avoided as a direct result of a change in the resource plan caused by a solar purchase. Tr. at 276.11. The main driver of the Company's need for additional capacity is its peak demand needs. In this context, Witness Lynch testified that DESC conducted a "Peak Demand Forecast" study, which used customer and energy sales forecasts and customer load characteristics to forecast the Company's seasonal peak demands. Tr. 276-12 – 276.13; Hr'g Ex. 4, JML-2. As a result of this study, DESC expects its winter peak demand to be higher than its summer peak demand over the 15-year planning horizon under normal weather conditions.[14] Tr. at 276.13.

DESC also updated its "2018 Reserve Margin Study" and provided more analysis to establish the winter and summer peak demand risk related to extreme weather. Tr. at 276.17. Specifically, Witness Lynch testified that the Company developed three separate equations to study DESC's reserve margin needs for both the summer and winter periods, taking into account the Company's Virginia and Carolina Reserve Sharing Group ("VACAR") requirements as well as its demand-side and supply-side risk reserve requirements. *Id.*; Hr'g Ex. 4, JML-3. As a result of that study, DESC determined that it requires a 14.3% reserve margin in the summer and a 20.2% reserve margin in the winter, which supports its continued use of a 14% minimum summer reserve margin and a 21% minimum winter reserve margin. Tr. at 276.18. Even with this level of reserve

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[14] Witness Lynch explained that this result largely is a consequence of changes in customer usage patterns resulting from energy efficiency and conservation having different seasonal impacts and that there are more effective opportunities to conserve electricity in summer than winter.

margins, however, Witness Lynch testified that the probability of load exceeding capacity at least once in the next 10 years is about 28%. Tr. at 276.21. He also testified that the probability of not having enough capacity to meet customer load and VACAR requirements at least once in the next 10 years is about 54%. *Id.* Under such scenarios, Witness Lynch also testified that there is no certainty that one or more of our neighboring utilities will not also be experiencing high demand and unable to provide capacity. *Id.*

As further support for its reserve margin policy, DESC also conducted an LOLE study in which it analyzed 15 years of load data, normalized to 2019 forecasted levels, and calculated the LOLE associated with each reserve margin. Tr. at 276.22 – 276.23; Hr'g Ex. 4, JML-4. The load data also was adjusted in two ways: 1) to produce seasonal peaks equal to those forecasted for 2019, and 2) to scale the data so that it had the same annual energy as 2019. These two approaches yielded similar results with an average median value of 17.7%, which is more than DESC's base reserve margin policy of 14% in the winter season and 12% in the summer season. Tr. at 276.23. DESC's base reserve margin therefore is riskier than the LOLE standard of an outage expectation of 1 day in 10 years and reflects a risk level of 3 days in 10 years. Tr. 276.24. However, DESC Witness Lynch testified that the Company believes its additional peak reserve resources, which mostly consist of demand response programs, will mitigate some of that added risk. *Id.*

Accordingly, DESC determined that it will need capacity in the future in order to meet its forecasted winter peak load. DESC also concluded that, as more and more incremental solar is added to its system, each increment will affect fewer daily peaks than previous increments and that, eventually, adding more solar capacity will no longer affect the summer peak. Because DESC needs capacity in the winter, and solar does not provide capacity either on early winter mornings before sunrise when the system peaks or during non-peak hours on most non-summer days when the system peaks before sunrise or after sunset, DESC concluded that incremental solar will not allow DESC to avoid any future capacity costs. The Company therefore determined that the capacity value of additional solar QF generation is zero. Tr. at 276.11.

ORS Witness Horii disagreed with DESC's position regarding avoided capacity costs, however. Specifically, ORS asserts that avoided costs should be considered in the context of DESC's comprehensive capacity needs over the entire year. Tr. at 695.34. Witness Horii also asserted that the Company's approach is flawed due to excessive focus on the demand part of system planning and insufficient recognition of the risk from generator unit outages. Tr. at 695.35. Witness Horii therefore testified that DESC failed to recognize the outage risks that exist over non-winter months. *Id.* Using DESC's ELCC analysis, Witness Horii concluded that solar resources should receive a credit equal to 24% of their nameplate capacity. *Id.* Alternatively, and recognizing the declining capacity benefits of solar at higher penetration levels, Witness Horii suggested that 37% of the existing 598 MW of solar nameplate capacity should be counted towards DESC's capacity needs. Tr. at 695.36. He also suggested that 11.8% of the next tranche of solar to be implemented using Rates PR-1 and PR-Standard Offer should be recognized. Tr. at 695.35 – 695.36. ORS Witness Horii also questioned DESC's assumption that it would purchase additional capacity from the market at low prices, which assumes a low-cost capacity resource instead of the standard CT unit. Tr. at 695.40. He also questioned the Company's exclusion of low-cost market purchases in the change case. *Id.*

SCSBA Witness Burgess also questioned DESC's analysis of the capacity value of solar, even though he recognized that DESC has experienced its annual peak load hour during winter in recent years. Tr. at 523.48. Instead, Witness Burgess suggests that there may be some future years where summer peak exceeds winter peak. *Id.* He also suggests that it is inappropriate for DESC to plan for serving load on one peak hour of the year that has the highest probability of an outage and, instead, the Company should consider the other hours of the year that have smaller probabilities of an outage. *Id.* Therefore, Witness Burgess posits that it is more appropriate to "place a series of smaller bets on the second, third, and fourth ranked" possibilities so as to potentially reduce the overall risk of QF investments. *Id.* He also suggests that load growth and load shapes may shift over the next ten years. Tr. at 523.51. Like Witness Horii, Witness Burgess further testified that DESC's ELCC analysis suggested solar has a capacity value of approximately 24% of nameplate capacity. Tr. at 523.56. He also stated that solar has a meaningful contribution to reducing the overall probability of an outage and, thus, has capacity value. Tr. at 523.57. On this basis, Witness Burgess suggested using DESC's ELCC value to determine capacity payments or to adjust the weightings to more accurately reflect DESC's summer peak load hours. Specifically, Witness Burgess suggested using a "Technology-neutral Seasonal Allocation Method" in which the resulting avoided costs are applied based on when QF production occurs and its coincidence with the seasonal peak periods, regardless of the underlying technology. Tr. at 523.59 – 523.61.

After considering the evidence of record on this issue, the Commission concludes that DESC's position that incremental energy supplied by solar QF facilities will not allow it to avoid any future capacity is reasonable. As an initial matter, the Commission recognizes that avoided costs are estimates based upon reasonable, future projections of an electric utility's cost to construct, maintain, and operate facilities or purchase resources as needed to safely and reliably serve customer load. The Company has presented substantial analyses reasonably demonstrating that its need for capacity will be driven by the need to meet winter peaks.

The Commission finds that the amount of solar generation under existing PPAs has had or will have the effect of reducing the net summer and winter load to be served by DESC. These facilities will be compensated to reflect this benefit pursuant to the avoided costs in effect at the time they executed their interconnection agreements, which are reflected in their PPAs. However, the question posed in this proceeding is what benefits will *incremental* solar provide to DESC in the form of delaying or avoiding the need for capacity benefits. The Commission finds that, through its Capacity Value of Solar Study, the Company has demonstrated that the existing amount of solar generation under contract has allowed it to reduce its summer peak needs to a point where the net peak to be served by the Company will occur at or after 8:00 p.m. when solar is no longer generating. The Commission therefore finds that adding any additional solar generation will only serve to reduce DESC's summer load, but not any capacity that may be needed to meet its net summer peak needs. In addition, the Company has reasonably demonstrated that existing solar has had the effect of pushing its net winter peak earlier in the day and that its forecasted winter peaks will occur before sunrise. It is apodictic that solar cannot generate energy before the sun rises or after the sun sets. Because the net summer and winter peaks to be served by DESC occur when the sun is not shining, the Commission therefore finds that any additional solar will not allow the Company to avoid or delay any future capacity expansions. Accordingly, the Commission finds that DESC's proposal to set the avoided capacity costs at zero is appropriate.

For these same reasons, the alternatives suggested by ORS and SCSBA also are unreasonable. In addition, however, the Commission finds that their proposals to rely upon the ELCC methodology estimates offered by DESC, which they suggest imply an average capacity value for solar of 24% of nameplate capacity, is inappropriate for use in this proceeding. The testimony of Witness Lynch demonstrates that the ELCC methodology is an application of the

LOLE methodology, which addresses average risk for the entire year. The LOLE methodology can hide an unacceptable risk level on the peak day and, therefore, is inappropriate to use when forecasting weather spikes in seasonal peaks. Instead, the related risk must be directly analyzed as DESC has done in this proceeding.

The Commission also finds that SCSBA's "Technology-neutral Seasonal Allocation Method" is inappropriate for use in this proceeding. By advocating for this methodology, SCSBA requests that the Commission approve a single QF rate that would be paid regardless of the nature of the underlying technology. However, the record reflects that stand-alone solar generation has a unique profile that is non-dispatchable and is not similar to other QF resources such as natural gas-fired generation. For this reason, the Commission finds that an accurate avoided cost for incremental, non-dispatchable stand-alone solar can only be captured using a solar specific avoided cost calculation. In making this finding, the Commission also recognizes that Act No. 62 provides "[a]voided cost methodologies approved by the commission may account for differences in costs avoided based on the … resource type of a small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-20(B)(3).

In short, the Commission finds that DESC has presented substantial evidence demonstrating that incremental solar QF energy will not have any effect on its need for future capacity. The Commission also finds that the positions advocated by ORS and SCSBA are inappropriate and reflect only broad assumptions by its witnesses, propose to estimate avoided costs based primarily upon supposition, and do not match the rigorous analyses performed by the Company to directly estimate the avoided costs associated with incremental solar QF generation.

6. Operational Issues Related to Solar

DESC has demonstrated that the integration of solar energy presents unique operational challenges for a large-scale utility tasked with generating electricity to meet customer demand across its service area, even during a given day. More particularly, DESC Witness Bell explained that, because photovoltaic ("PV") solar panels convert light directly into electricity, the amount of sunlight on the panels dictates the electrical output of each facility. Tr. at 167.3. Uncontrollable factors, including time of day and local weather conditions, influence the amount of energy that can be produced. *Id.* This means that PV solar produces electricity independently of customers' demand for energy. *Id.* This is unlike dispatchable generation, such as those from natural gas-fired generating facilities, that can be controlled and adjusted to produce more or less energy as is needed to meet demand. *Id.*

Witness Bell explained that, in general, PV solar facilities begin producing energy just after sunrise, with their output increasing for the next several hours in the day, depending on cloud cover. *Id.* DESC's data shows output averages of about 74% of rated capacity by around 11 a.m. *Id.* However, in addition to the more predictable ramps at the beginning and end of the day, unpredictable minute-to-minute variability occurs throughout the day depending on weather conditions. *Id.* To illustrate this, DESC presented charts showing examples of production profiles on selected days in 2019, each of which displayed 1-minute data from 6 a.m. to 8 p.m. on certain historical days. Tr. at 167.4-167.10. Those charts showed a wide range of scenarios, including high production days with more and less aggressive ramping periods, moderate and low production days, and days with large fluctuations caused by changes in cloud cover throughout the course of the day. *Id.*

Witness Bell explained that when unplanned drops and increases occur in solar generation—which his demonstrative charts showed could reflect changes to the order of hundreds of megawatts within a day—DESC must ramp up or ramp down its dispatchable generators in order to cover the fluctuations and meet customer demand. Tr. at 167.12. This means that DESC must maintain sufficient generation capability in reserve in order to compensate for the intermittent variability of solar and to meet this demand. In addition to being variable moment to moment, Witness Bell explained that solar generation can also vary widely from the solar generation forecasts provided by solar operators and Company forecasters, which creates an additional need for reserves. *Id.* In recent years, DESC has experienced a significant increase in PV generator connections, and expects an even greater increase in the near future. Tr. at 167.10-167.11.[15] Ultimately, DESC anticipates that solar generation will exceed its ability to provide adequate reserves unless DESC maintains more hourly operating reserves or adds more quick-start resources to its system. *Id.*

Witness Bell explained that DESC is subject to requirements established by NERC and the SERC Reliability Corporation. Tr. at 167.14. As noted, the Company is also a signatory to VACAR through which it is required to maintain reserve generation capability at all times in the event of a contingency—that is, a reserve call from a neighboring utility, a sudden loss of generation such as when a dispatchable generating facility is unable to generate electricity, or unexpected and higher demand on DESC's system. *Id.* Thus, when the territorial load exceeds forecast, or non-dispatchable solar generation is not producing the expected level of electric generation, DESC must ensure that other generation is producing power to meet load, while making additional generation supply available to maintain the reserve requirement. *Id.* Under these circumstances,

[15] Witness Bell testified that, as of August 2019, DESC had a total of 511 MW of solar generation in commercial operation on its system, and that by the end of 2020, the Company expects to have a total of 1,152 MW of solar facilities interconnected with its system, which represents about one quarter of the Company's current peak demand. *Id.*

DESC must have generators available or online that are capable of quickly and reliably producing electricity so that any sudden shortfall can be met. *Id.*

Witness Bell explained that contingency reserves must be supplied on demand within fifteen minutes. Contingency reserves include both "spinning" and "non-spinning" reserve requirements. Tr. at 167.15. Spinning reserves are those provided by generators that are already online but not operating at full capacity and therefore can immediately generate additional electricity to serve the load. *Id.* Non-spinning reserves may be supplied by both online and offline generators that can be fully loaded within fifteen minutes. *Id.* Witness Bell explained that the generators with the fastest response capability are quick-start internal combustion turbines ("ICTs"), some hydropower facilities, and pumped storage generators ("Pumped Storage"). *Id.*

Witness Bell explained that the only way to increase reserves from ICTs and Saluda Hydro is to construct additional units. *Id.* DESC's reserves from quick starts and Saluda Hydro, he explained, have been fully utilized for years, and no additional reserve value can be gained from those existing units. *Id.* While he explained that Pumped Storage does supply both spinning and non-spinning reserves, Witness Bell further explained that the optimal use of Pumped Storage is dictated by economic factors. *Id.* Creating additional reserves by holding back Pumped Storage adds fuel costs in most circumstances because the output from higher-cost generating units must be increased to replace the power. Tr. at 167.15-167.16. Witness Bell explained that DESC can increase its reserves by operating more coal and gas-fired baseload units; however, doing so may require DESC to operate its natural gas or coal-fired generating facilities under low load conditions or at an output level that is less efficient, i.e. more costly, than the optimal level for which they were designed. Tr. at 167.16. Thus, Witness Bell explained, there is a cost to operating the generating units that provide these higher reserve levels, and those costs increase as more reserves are required. *Id.*

As it concerns DESC's reserve requirements to address these issues with the variability of solar, CCL/SACE Witness Stenclik testified that the Navigant Study (discussed *infra*) improperly assumed high reserve requirements for DESC. Tr. at 629.5. More specifically, he testified that the study does not accurately capture DESC's operating practices because DESC does not currently require operating reserves for existing solar generation. *Id.* He also testified that the Navigant Study failed to account for aggregation benefits that naturally reduce the relative forecasting errors and resource variability as the solar generation fleet grows. *Id.* Witness Stenclik also testified that the analysis used an excessive 4-hour ahead forecast, overstating the forecast error that may impact actual operations. *Id.*

Responding to the criticisms of Witness Stenclik, Witness Bell testified that DESC's actual operating practice requires additional reserves equaling 40% of actual or forecast solar output to account for solar intermittency. Tr. at 176.7. This is in addition to contingency reserves, which are a different form of reserves altogether. The 40% flexible reserve allows the system to respond to solar intermittency that exceeds 15 minutes and still maintain the operating reserves necessary to respond to the largest thermal unit in operation at that time tripping offline. Tr. at 176.7-176.8. Witness Bell explained that solar intermittency is different from a thermal unit dropping offline, which happens in a single event, and the effects of which in terms of loss of generation can be calculated precisely. Rather, the loss of solar generation often occurs as a decline in generation that stretches over multiple 15-minute intervals, and can evolve over several hours. Tr. at 176.8-176.9.

Also, because the probability is significant of a coincidence of a thermal unit's forced outage and a large, unplanned drop in solar generation persisting for hours, Mr. Bell explained that prudent operators must consider and plan for both contingencies happening at the same time, and must also keep in mind the ramp-up time for the next available unit—if the next available unit takes 3-4 hours to ramp up to supply load, then the operator must make system adjustments sufficiently ahead of time to allow that unit to reach generation capacity. Tr. at 176.9. It is for these reasons, Witness Bell explained, that reserves for solar intermittency must be in addition to the existing contingency reserve requirement, and additional reserves of less than 40% would expose DESC's customers to unacceptable risks. Tr. at 176.9-176.10.

The Commission agrees that, given the intermittent nature of solar generation, the severity of which can evolve over the course of several hours in a day, DESC's decision to maintain reserves for solar in addition to those otherwise required for the operation of DESC's system is reasonable, and that to do otherwise would expose customers to an unreasonable risk. As Witness Bell testified, DESC must assume that an unplanned drop in solar generation will, at some point, coincide with an outage of a large thermal unit. DESC has a responsibility to supply enough electricity to meet the demand of its customers, and to maintain its other reserve requirements. It therefore has a responsibility to plan for, and be ready to respond to such a scenario. The Commission therefore finds that DESC's reserve requirements to account for the intermittent nature of solar are reasonable and appropriate.

Witness Stenclik also expressed concern that the Navigant Study imposed additional fixed solar reserve requirements for each hour of the year rather than being a function of hourly forecasted solar generation. Tr. at 629.5. Witness Bell explained, however, that DESC uses hourly forecasted solar production, as well as actual solar production, to plan and maintain reserves on an hourly basis for real-time system operations, which limits the additional reserves for solar and the associated cost to daylight hours. Tr. at 176.10. The Commission agrees with the testimony of Witness Bell in this regard and finds that it is reasonable, and that the analysis did not overstate required reserves or associated costs in this manner.

7. Resource Plan

In analyzing its resource needs, the Company also performed a resource study to assess the cost of generation that could meet DESC's resource plan needs. Tr. at 308.4; Hr'g Ex. 6, JWN-1. Specifically, the Company used 19 resource plans evaluated under 4 different sets of assumptions for a total of 76 different scenarios. Tr. at 308.3. The four sets of assumptions included 1) Base Gas Prices with Zero CO2 Costs, 2) High Gas Prices with $15/ton CO2 costs, 3) High Gas Prices with Zero CO_2 Costs, and 4) Base Gas Prices with $15/ton CO_2 Costs. Tr. at 308.6. In each case, generation was added over a 30-year horizon, then modeled using DESC's hourly dispatched model. Hr'g Ex. 6, JWN-1. The Company then extrapolated costs for another 10 years and compared the scenarios using each scenario's 40-year levelized present value. *Id.* DESC determined that base gas prices is the most likely gas scenario with zero CO_2 costs. Tr. at 308.6. Based on this assumption, DESC determined that the addition of two 540 MW combined cycle gas generation plants in the winters of 2029 and 2040 would result in the lowest cost resource plan. Hr'g Ex. 6, JWN-1. On this basis, DESC calculated its avoided energy costs using this resource plan because it is the lowest-cost resource plan identified. To calculate avoided capacity costs of QFs that would potentially displace peaking resources, however, DESC determined that it would be more appropriate to use a plan that is populated with peaking resources. Tr. at 319.25. Accordingly, DESC proposed to use an ICT to calculate avoided capacity costs.

SCSBA Witness Burgess testified that the use of a new ICT peaking facility was incorrect and biased against QFs, however. Tr. 523.41. Instead, he suggested that there has been a growing trend towards more flexible, aero-derivative types of peaking facilities, which might be more efficient, but also more expensive in terms of upfront capital costs. Tr. at 523.42. Witness Burgess also recommended a capital cost assumption that represented the midpoint between the capital costs of the two types of peaking facilities. Tr. at 523.44. In response, Witness Neely testified that the capital cost of peaking resources used by DESC accurately reflects the cost of procuring and installing a 100 MW aero-derivative simple cycle generating unit with a net capacity of 93 MW on DESC's system. Tr. at 319.26. He further testified that this choice of peaking resource is appropriate because it is the lowest-cost peaking resource plan identified and that SCSBA Witness Burgess' suggestion would require a more expensive plan. *Id.*

Witness Burgess also criticized DESC's estimates of the cost of capacity purchases from other neighboring utilities in years 2022 through 2028. Tr. at 523.40 – 523.41. He posited that the cost estimates used by the Company for these purchases is relatively low, does not accurately reflect market value, and therefore artificially depresses the avoided capacity cost in the change case. Tr. at 523.45. In response, Mr. Neely testified that the purchased capacity component reflects a 3-month winter purchase or winter demand response resource. Tr. at 319.27. However, he noted that Witness Burgess inappropriately compared this cost to an annual cost for capacity from PJM and that, if SCSBA's suggestion was properly applied, it would result in a lower avoided cost of capacity cost, not a higher one. Tr. at 319.27 – 319.28.

The Commission finds that the resource plan scenarios proposed by DESC to calculate avoided costs are reasonable. But for the Company being required to purchase electricity generated by QFs, it would be reasonable and appropriate for DESC to plan for its resource needs based on adding capacity that would meet its needs and at the lowest reasonable cost. Both the expansion plan set forth in the Company's 2019 IRP and the use of an ICT to calculate capacity costs are reasonable, as they represent the lowest-cost plans under reasonable assumptions. Accordingly, the Commission approves the use of these plans to calculate avoided costs as proposed by DESC.

8. Proposed Avoided Costs and Methodology

In connection with this proceeding, DESC proposes to use the DRR methodology to calculate avoided energy costs over two time periods—"short-run" avoided energy costs, which are for the 12-month period of May 2019 through April 2020, and "long-run" avoided energy costs, which are for the 10-year period of 2020 through 2029. Tr. 308.8 – 308.9. Long-run avoided energy costs are then divided into two groups of five years each: 2020-2024 and 2025-2029. Tr. at 308.9. DESC also proposes to calculate avoided capacity costs using a 10-year period. *Id.* Witness Neely testified that the 10-year period for long-run avoided energy and capacity costs was appropriate because using projected costs beyond the 10-year period required by Act No. 62 would be speculative and could increase the costs paid by DESC's customers. Tr. at 308.13.

Again, Witness Neely testified that to calculate avoided energy costs for QF facilities under Rate PR-Standard Offer, DESC uses PROSYM to estimate the change in production costs that result from serving the loads in the base case and the change case. Tr. at 308.11. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. *Id.* The avoided costs are then accumulated into four time-of-use periods. *Id.* The change case for solar QFs is derived from the base case by subtracting a 100 MW power purchase modeled after a solar profile. *Id.*

For avoided capacity costs under Rate PR-Standard Offer, DESC takes a similar approach. *Id.* Witness Neely testified that using the resource plan in its latest IRP or an updated resource plan if appropriate, DESC calculates the incremental capital investment related revenue required to support the existing resource plan. *Id.* For the calculation of avoided capacity costs, DESC derives a change case in its resource plan by considering the impact of a QF purchase from a 100 MW facility. Tr. at 308.11 – 308.12. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. Tr. at 308.12. Witness Neely testified that this method is reasonable because it identifies adjustments to the utility's expansion plan that are attributable to purchases from QFs and accurately reflects the capacity cost benefits that would result from the QF purchase. *Id.*

Witness Neely stated that, because incremental solar QFs do not affect the resource plan and therefore avoid no future resources or their cost as discussed more fully above, the avoided cost for solar QFs subject to Rate PR-Standard Offer is zero. *Id.* For non-solar QFs that qualify for the Standard Offer Rate, Witness Neely testified that the avoided capacity cost is $73.46/MWh, but this value only applies for a limited period of time. *Id.* These avoided capacity rates will be paid during the months of December, January and February for energy generated from 6 a.m. to 9 a.m. *Id.* In order to qualify for this credit, the Seller's generation should be fully dispatchable during all of the identified capacity credit hours. *Id.*

Witness Neely therefore testified that the following avoided costs should be approved for Rate PR-Standard Offer:

STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/MWh)

Time Period	Peak Season Peak Hours ($/MWh)	Peak Season Off-Peak Hours ($/MWh)	Off-Peak Season Peak Hours ($/MWh)	Off-Peak Season Off-Peak Hours ($/MWh)
2020-2024	32.80	27.97	33.01	30.73
2025-2029	38.39	31.66	41.91	35.19

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/MWh)

Time Period	($/MWh)
December, January, February 6 a.m. to 9 a.m.	73.46

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/MWh)

Time Period	Annual ($/MWh)
2020-2024	16.76
2025-2029	15.66

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Solar QFs ($/MWh)

The avoided capacity costs for solar QFs are zero.

Tr. at 308.14.

Witness Neely also testified that Rate PR-1 and PR-Standard Offer would not be applicable to QFs greater than 2 MW. Tr. at 308.15. Instead, Witness Neely stated that the Company would negotiate separate contracts for these projects and would calculate the avoided costs for these projects using the same methodology outlined above, but with unit-specific data and the other requirements described in the Company's proposed Rate PR-Avoided Cost Methodology. *Id.*

Regarding QFs in the future that seek to interconnect both solar generation and storage, DESC has not proposed a tariff for these types of projects in this docket. Rather, by settlement agreement previously approved with modifications by the Commission in Order No. 2018-804, the Company agreed to file rate schedules for solar with storage on or before December 31, 2019. The Company represented that it was prepared to meet that deadline.

For Rate PR-1, Witness Neely testified that the Company uses the same methodology to estimate avoided energy costs for solar QFs as it did for solar QFs for Rate PR-Standard Offer, except that the short-run avoided energy costs are estimated for the period May 2019 through April 2020. Tr. at 308.18. He also explained that losses for Rate PR-1 are calculated at the primary distribution level. *Id.* For non-solar QFs, Witness Neely testified that DESC uses PROSYM to estimate the change in production costs that result from serving the base case and the change case. *Id.* The avoided energy costs then are accumulated into four time-of-use periods, and non-solar QFs would be paid based on how much energy they produce in each of these periods. *Id.* For avoided capacity costs, Witness Neely testified that DESC calculates the incremental capital investment related revenue required to support the existing resource plan and considers the impact of a QF purchase from a 100 MW facility on the resource plan. Tr. at 308.19. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. *Id.*

Based on this methodology, Witness Neely testified that the avoided capacity cost component for solar QFs under Rate PR-1 is zero because these facilities do not affect the resource plan. *Id.* For non-solar QFs that qualify for the PR-1 Rate, the avoided capacity cost is $0.07346/kWh, which will be paid during the months of December, January, and February for energy generated from 6 a.m. to 9 a.m. *Id.* Witness Neely also stated that the capacity payment is available only to generators capable of providing power in all of the identified hours. *Id.* In sum, DESC's proposed Rate PR-1 avoided costs are as follows:

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours ($/kWh)	Peak Season Off-Peak Hours ($/kWh)	Off-Peak Season Peak Hours ($/kWh)	Off-Peak Season Off-Peak Hours ($/kWh)
May 2019-April 2020	0.03075	0.02566	0.03330	0.03363

PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December, January, February 6 a.m. to 9 a.m.	0.07346

PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	Year Round ($/kWh)
May 2019-April 2020	0.02763

PR-1 RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

The avoided capacity costs for solar QFs are zero.

Tr. at 308.20 – 308.21.

In response to the testimony of DESC regarding the calculation of avoided costs, ORS Witness Horii testified that the changes in avoided energy costs from those previously approved by the Commission in Docket No. 2018-2-E largely are due to recent decreases in fuel prices. Tr. at 695.26. He further noted that changes in load and components of electric supply are relatively slight and confirmed that DESC's updates to the avoided energy costs are a reasonable and consistent result of the approved DRR methodology. *Id.* Even so, ORS Witness Horii disagreed with DESC's estimate of avoided energy costs for solar resources, alleging that DESC overstated the need for additional operating reserves to accommodate the integration of solar resources. Tr.

at 695.27. This issue has been previously discussed by the Commission earlier in this Order in Section V.B.4. Because the Commission finds that DESC's proposed use of 35% operating reserves is reasonable and appropriate to calculate avoided energy costs, it does not find Witness Horii's testimony in this regard to be persuasive.

ORS Witness Horii also testified that, notwithstanding the operating reserve level change, there were certain flaws in the calculation methodology used by DESC. Tr. at 695.29 – 695.30. After ORS raised this issue, however, Witness Neely testified that the Company reviewed its calculations and identified an error in the implementation of the operating reserve methodology. Tr. at 319.6. He stated that the Company then promptly addressed the issue and corrected the calculations by filing an amended version of his direct testimony with the Commission. Tr. at 319.6 – 319.7. After reviewing these issues, the Commission finds that the flaws identified by ORS Witness Horii were properly addressed with the filing of Witness Neely's amended testimony. Notwithstanding this issue, the Commission finds that Witness Horii's proposed avoided energy costs are unreasonable. Witness Horii acknowledged in his testimony that solar integration costs exist, tr. at 695.8, but he failed to include any of these costs in his proposed energy costs. Accordingly, ORS's proposed avoided energy costs effectively shifts integration costs to DESC's customers, which is directly contrary to PURPA, FERC's implementing regulations and orders, and the mandates of Act No. 62. *See* S.C. Code Ann. § 58-41-20(A). The Commission therefore finds that it would violate Act No. 62 to adopt ORS's proposed avoided energy costs in this proceeding as the proposal impermissibly shifts costs onto customers.

Regarding avoided capacity costs, ORS Witness Horii disagreed with certain inputs and assumptions used by DESC to develop its estimates. Witness Horii first stated that the Company incorrectly concluded incremental solar provides no capacity value in the winter and that DESC should have used the ELCC capacity value in estimating avoided capacity costs. Tr. at 693.33 – 695.35. He also stated that the Company should have used a 93 MW change in generation instead of a 100 MW change in generation. Tr. at 695.39. As discussed previously, DESC's conclusion that incremental solar provides no capacity value in the winter and that solar does not allow the Company to avoid any future capacity needs is reasonable and appropriate. The ELCC method and the use of a 93 MW change in capacity also are not appropriate for use in calculating avoided capacity costs as discussed in more detail above.

Witness Horii also questioned the Company's calculations for cost of avoidable capacity, stating that these calculations were based on the cost of low-cost purchased power instead of the costs of a CT unit as reflected in the Company's IRP. Tr. at 695.33. However, Witness Neely stated that the inclusion of these low-cost resources was appropriate because the resources were meant to provide needed peaking reserves for the top 10-20 days of highest capacity need each year. Tr. at 319.11. He further testified that, because only half of the peak days would occur in the winter, it would be inappropriate to add a generating resource to only cover needs for 5-10 winter peak days a year. *Id.* The Commission finds that the Company's position is reasonable. Although Witness Horii asserted that the frequency of such needs is irrelevant if a capacity seller has to hold and provide that capacity to DESC, he provided no information to support this claim. To the contrary, Witness Horii acknowledged that neighboring utilities have had recent capacity surpluses that allow for some low-cost capacity purchases. Tr. at 697.9. For planning purposes, the Commission therefore finds that the Company's proposal is reasonable and is appropriate for use in these proceedings.

Regarding the Company's use of a CT turbine for other capacity needs, Witness Horii claimed that the Company should have used a 20-year economic lifetime, such as that used in jurisdictions such as California, as opposed to DESC's proposed 60-year lifetime. Tr. at 695.38. In doing so, Witness Horii suggested that the Company is spreading the capital-related costs of the CT over an excessive number of years. *Id.* However, Witness Neely pointed out that the Commission previously has approved a depreciation study, which provides that the life span of peaking turbines, such as CT units, is between 60 and 75 years. Tr. at 319.12. In response, Witness Horii stated that a 60-year life span could have been used if the Company had included major overhaul costs and that if those costs were included, the resulting avoided capacity costs "likely" would be similar in magnitude to the estimates produced using a 20-year economic life without major overhaul costs. Tr. at 697.10. However, Witness Horii did not provide any information regarding how much those costs might be. Moreover, by making the unsupported statement that these costs "likely" would be similar in magnitude, ORS is inviting the Commission to speculate as to whether those costs would be appropriate. The Commission finds that it would be unreasonable to do so. In contrast, DESC has presented a reasonable estimate of its avoided capacity costs based on reasonable assumptions and depreciation periods previously approved by the Commission. The Commission therefore finds that it is reasonable and appropriate for the Company to use a 60-year economic life span for a CT to calculate its avoided capacity costs.

On behalf of SCSBA, Witness Burgess suggested that, rather than adopting DESC's proposed avoided costs, the Commission instead should approve avoided cost rates that are on the higher end of a "zone of reasonableness." Tr. at 523.11. He suggests that this method would marginally increase customer costs, but that such costs would be transparent, stable, and tied to a QF's performance. Tr. at 523.12. However, Witness Burgess provided no evidence, much less substantial evidence, demonstrating the bounds of this purported "zone of reasonableness" or what avoided costs values would be appropriate for adoption by this Commission using such a nebulous criterion. In this regard, the Commission finds that setting avoided costs on this basis would require the Commission to engage in speculation instead of establishing just and reasonable avoided costs as directed by the General Assembly in Act No. 62. In addition, and as acknowledged by Witness Burgess, such an exercise would "increase customer costs," even if only marginally. Again, the Commission finds that taking such action would shift the risk of solar developments onto DESC's customers and arbitrarily increase their rates, both of which would directly violate the requirements of PURPA and Act No. 62.

Witness Burgess also questioned DESC's proposal to use a different rate methodology for solar and solar with storage, stating that a resource-specific approach raises significant concern about the ability of separate rates to properly represent the full suite of QF technological possibilities. Tr. at 523.19. Instead, Witness Burgess suggested that a single QF avoided cost value be determined for projects up to 2 MW that reflects the value to DESC's system regardless of the fact that the underlying record reflects solar and solar with storage are different resources with different generation profiles. Tr. at 523.20. In order to determine the most accurate avoided cost for each technology, including the amounts of energy and capacity each technology allows DESC to avoid, it therefore is appropriate to consider these technologies separately. Every project that currently comprises the 1,048 MW of solar to be interconnected with DESC's system consists of non-dispatchable, variable solar generation. Tr. at 319.20. The Commission therefore finds that it is appropriate to calculate the solar avoided cost based on non-dispatchable solar. The Commission further recognizes that the Company's proposed Form PPA allows utilities to calculate a resource-specific avoided cost value for other QF facilities such as flexible solar. For these reasons, the Commission finds that calculating a single QF avoided cost value as Witness Burgess suggests, would not only be inappropriate but also would result in customers having to bear excessive costs, which is directly contrary to the requirements of PURPA and Act No. 62.

For the reasons stated above and after reviewing the evidence of record and the positions advanced by the parties, the Commission finds that the avoided costs and the avoided cost methodology proposed by DESC is reasonable and complies with the requirements of Act No. 62.

9. Variable Integration Costs

As part of its avoided cost methodology and proposals, the Company also seeks to account for the costs it incurs to integrate variable energy supply from solar. As previously discussed, DESC experiences real and measurable costs to integrate the energy supplied by solar generators due to the variable nature of the energy supply. With respect to future solar QFs who seek to provide DESC with energy under Rate PR-1, Rate PR-Standard Offer, or Rate PR-Form PPA, the Company proposes to incorporate these integration costs directly into the avoided cost values by modeling the system with higher operating reserves. As stated by Witness Neely, DESC observed that additional operating reserves equal to 35% of the installed solar generation is sufficient to cover most of the one-hour solar intermittency. Tr. at 319.31. Therefore, the Company modeled its avoided cost calculations with additional operating reserves equal to 35% of the installed solar generation during solar generating hours. *Id.* Witness Neely stated that this process allows the Company to incorporate the integration costs into its model and there is no need to include an additional charge to reflect the avoided costs for integration. Tr. at 308.10. As previously discussed, the Commission finds that this proposal is reasonable and appropriate for inclusion in the avoided cost methodologies approved in connection with this proceeding.

However, this methodology would only apply to future solar QFs that seek to provide DESC with energy under Rate PR-1, Rate PR-Standard Offer, or Rate PR-Form PPA and would not apply to QFs that have existing PPAs with DESC. In this regard, DESC Witness Neely testified that there are approximately 700 MW of PPAs with a variable integration charge ("VIC") clause that allows DESC to recover costs associated with the variable nature of solar, which have not been captured in previous avoided cost calculations. Tr. at 308.9. He further explained that the Company experiences real and measurable costs to integrate the energy supplied by solar generators due to the variable nature of the supply and that the Company plans to recover these costs from solar generators with PPAs that contain the VIC clause. Tr. at 308.9 – 308.10. However, the VIC clause would not be applied to new PPAs; rather, DESC stated that it was more appropriate to address issues created by solar intermittency by modeling the system with higher operating reserves and that the associated costs would be reflected in avoided energy costs. Tr. at 308.10.

In order to calculate the VIC for these PPAs, Witness Neely stated that DESC employed Navigant Consulting, Inc. ("Navigant") and Company Witness Tanner who conducted a "Cost of Variable Integration Study" ("Navigant Study"). Tr. at 290.3; Hr'g Ex. 5, MWT-2. Witness Tanner testified that the scope and purpose of the study was to estimate the impacts that solar installations will have on DESC's system operations. Tr. at 290.5. He stated that it also establishes the resulting incremental integration costs for projects that are already under contract and have a VIC clause in their PPA and describes how the additional reserve requirements for DESC that are caused by solar will result in additional fuel costs. Tr. at 290.5 – 290.6.

Specifically, Witness Tanner stated that the Navigant Study evaluated the variable integration costs for two different scenarios of solar generation installed on the system. Tr. at 290.6. These scenario assumptions were developed to generally correspond with the amount of interconnected solar generation with PPAs that do not include a specific VIC clause and the tranche of solar with PPAs that do have a specific VIC clause. *Id.* The study also describes how the additional reserve requirements for DESC that are caused by solar can be incorporated into the avoided cost methodology in the future. *Id.* Finally, the study describes the requirements that solar projects must meet in order to avoid the need for DESC to implement additional reserve requirements. *Id.*

The initial analysis focused on establishing a benchmark for Navigant's PROMOD® production cost model that reflected DESC's actual system operating experience and the Company's own internal planning. Tr. at 290.7. The purpose of this initial analysis was to provide an appropriate and reasonable estimate of the Variable Integration Cost. *Id.* Navigant then conducted a solar uncertainty analysis, which estimated the forecast error for hourly generation from solar, by comparing solar forecasts with actual solar generation from the United States National Renewable Energy Lab's ("NREL") solar integration dataset. *Id.* Using this information, Navigant calculated the probability of how much less than expected solar facilities actually generate, which varies depending on the forecasted level of solar generation. Tr. at 290.12 – 290.13.

Witness Tanner testified that the analysis also considered the challenges the Company would experience if additional reserves are not added to the system. The Study provides examples and analyses of time periods when DESC operators would experience insufficient amounts of resources that would be needed to maintain system reliability and demonstrates that DESC needs to maintain additional reserves to safely and reliably operate its electric system in light of the variability in solar generation. Tr. at 290.7. Witness Tanner also testified that the study took into account the impact of geographic diversity of renewable resources and recognized that solar generation is not located in a single area, but in different places throughout a system. Tr. at 290.15 – 290.16. This geographic diversity means that there is variability in how weather will affect the generation output of dispersed solar installations at any given time. *Id.* The Study further allowed the model to change the operation of the Fairfield Pumped Storage System ("Fairfield") to minimize overall system cost while meeting the requirements for solar integration. Tr. at 290.20. As a result of this analysis, Witness Tanner testified that the incremental variable integration cost for solar and the resulting VIC charge is $4.14/MWh. *Id.*

Witness Tanner also stated that the Study evaluated alternative approaches to providing the necessary reserves including an analysis of the potential and cost to add new resources to the system as an alternative mitigation option. This involved estimating the Company's cost to maintain additional reserves necessary to integrate the variable energy generated by solar facilities. Specifically, Witness Tanner stated that the amount of 1-hour battery storage that can be added for the additional system costs of approximately $73.2 million is approximately 95 MW assuming future improvements in technology and cost declines through 2025. Tr. at 290.21. The amount of CT gas capacity that can be added is approximately 110 MW. *Id.* However, Witness Tanner stated that neither of these capacities is sufficient to provide the reserves needed to integrate the solar generation. Tr. at 290.22. Witness Tanner testified that the Study also considered the ability of solar projects to provide sufficient flexibility so that DESC does not have to add reserves. Tr. at 290.22. He further stated that, while detailed conditions would need to be defined in the future for solar projects willing to offer such flexibility, certain operating conditions would allow for DESC to avoid the need to increase reserve requirements in order to plan for potential drops in solar generation. *Id.* These conditions would include 1) giving DESC some ability to control the dispatch of the generation from the project; 2) being able to replace enough of the nameplate capacity of the project when called upon to make up for generation lower than forecasted; and 3) being able to maintain the replaced generation for sufficient time to avoid reliability challenges. *Id.*

ORS Witness Horii first took issue with the Company's proposal to calculate integration costs in one manner for Rate PR-1 and Rate PR-Standard Offer and in another way for the VIC. Tr. at 695.9. Similarly, SCSBA Witness Levitas asserted that it was inappropriate for DESC to embed integration charges in the avoided cost values for future PPAs as opposed to identifying them as a separate, stand-alone charge like DESC has proposed for the VIC to be charged to QF facilities with existing PPAs containing the VIC clause. Tr. at 451.33 – 451.34. As discussed previously, the Commission finds that, in setting the price for certain past PPAs, the avoided cost calculations approved by the Commission did not include the effect of solar generation on the operating reserves. However, the record reflects that certain of those PPAs contained terms that allowed VIC charges to be calculated in the future and recovered under the terms of the existing contracts. Tr. at 319.2. The Navigant Study has quantified these costs based on historical levels of solar generation. *Id.* By comparison, the avoided cost calculations and the methodology proposed by DESC in this proceeding directly incorporate the operating reserves associated with the next 100 MW of solar generation to be added to the system. Tr. at 319.3. The Commission therefore finds that it is reasonable to calculate the VIC for historical integration costs and to rely upon the proposed avoided cost methodology for any forward-looking integration costs.

ORS Witness Horii also criticized the Navigant Study, asserting that it did not use a balanced approach to forecasting operating reserves. Specifically, ORS Witness Horii stated that the Navigant Study did not seek to maintain a reasonable level of risk and instead modeled an excessive amount of additional reserve requirements. Tr. at 695.13. On this basis, Witness Horii suggested that, instead of using a 1% threshold for solar generation, the Company should have used 2%. Tr. at 695.15. Similarly, CCL/SACE Witness Stenclik stated that the 1% threshold was overly stringent and should have been higher. Tr. at 629.5. However, the Commission finds that these recommendations are unreasonable. Based upon the evidence presented, the Commission finds that using a 1% threshold as the estimate of solar uncertainty reflects an expectation that DESC would have an insufficient amount of generation due to unanticipated loss in solar generation approximately 30 to 50 hours per year. Tr. at 300.4. Using Witness Horii's suggestion would double this amount, meaning that there would be 60 to 100 hours per year when there may be insufficient capacity on DESC's system to respond to unanticipated drops in solar generation. The Commission finds that, in order to operate a safe and reliable system, this level of uncertainty simply is unreasonable and unacceptable and declines to adopt ORS's recommendation in this regard.

Witness Horii also expressed concern that the Navigant Study overstated reserve needs by holding reserve levels constant throughout each day of the year. Tr. at 695.22. Similarly, CCL/SACE Witness Stenclik stated that the study imposed fixed solar reserve requirements for each hour of the year rather than being a function of hourly forecasted solar generation, tr. at 629.5, and SCSBA Witness Burgess suggested that changes in reserve requirements by time period were not properly considered. Tr. at 523.81. However, the Commission recognizes that, in nighttime hours, DESC has more than enough reserves available from thermal units that are operating at less than full capacity. Tr. at 300.5. In the Navigant Study, the model only required that 240 MW be held in the business-as-usual (i.e., non-solar) reserves case. Tr. at 300.6. Further, the Navigant Study considered any change to system economics that results from holding additional reserves overnight by blending multiple reserve assumptions. Tr. at 300.10. Thus, the Commission finds that additional reserves required for solar integration are not a binding constraint on the system in non-solar hours and do not materially impact the overall system operating costs or contribute to the calculation of the VIC. The Commission therefore finds that the reserve needs identified in the Navigant Study are reasonable.

ORS Witness Horii also suggests that the Navigant Study's modeling requires operating reserves to provide solar integration services instead of potentially lower-cost types of reserves, such as non-spinning or supplemental reserves. Tr. at 695.28 – 695.29. He posits that DESC overestimated the additional costs of solar integration by increasing operating reserves through an expensive, fast-responding option to address a slow 1-hour problem. Tr. at 695.29. But as explained by Witness Tanner, operating reserves is a more general term for all reserves that are needed to operate the system and contingency, flexible, and regulating reserves can all be considered as subsets of operating reserves. Tr. at 300.8. Because multiple types of operating reserves must be held to meet system needs, the Commission concludes that the Navigant Study did not improperly overestimate solar integration costs as Witness Horii suggests.

Similarly, CCL/SACE Witness Stenclik states that the Navigant Study incorrectly analyzes solar data and overstates associated utility reserve requirements. In particular, he stated the analysis used an excessive 4-hour ahead forecast, overstating the forecast error that may impact actual operations. Tr. at 629.5. Similarly, SCSBA Witness Burgess suggested that it would be more appropriate to use a 2-hour forecast window or that offline CC units should be considered as providing operating reserves. Tr. at 640.8. However, the Commission finds that the Navigant Study used a generally accepted method for calculating the forecast error of solar generation using a data set provided by NREL that was created for the purpose of renewable integration studies. Tr. at 300.9. The Commission also finds that the Navigant Study was designed so as to avoid overstating reserve requirements, ensured that geographic diversity of solar generation was fully included, and properly balanced levels of acceptable risk with the cost of holding additional reserves. *Id.*

Regarding offline CCs, the record reflects that a CC can only provide operating reserves if it is operating and has the immediate capability to ramp up. Tr. at 300.17. Even so, the Commission finds that the Navigant Study properly allowed CCs to provide reserves in the model if starting a CC unit is the most cost-effective solution. Tr. at 300.17 – 300.18. The Commission therefore finds that SCSBA's suggestion is without merit.

The Commission also is not persuaded by Witness Stenclik's assertion that the study failed to include the full capabilities from Fairfield and interruptible load. Tr. at 629.5. Witness Tanner's direct testimony specifically discusses that the Navigant Study allowed Fairfield to change its operation to minimize overall system cost while meeting the flexible reserve requirements for solar integration. Tr. at 300.10 – 300.11. Accordingly, the Commission finds that the Navigant Study properly configured Fairfield to provide flexible reserves both when it is pumping and when it is offline. Regarding interruptible load, Witness Tanner stated relying upon interruptible load to meet daily operating reserve (contingency and flexible) requirements would significantly increase the number of curtailments and result in substantial additional economic impacts to interruptible customers. Tr. 300.11. The Commission therefore finds that it is appropriate to assume that only 100 MW of interruptible load can count towards the contingency reserves and no extra interruptible load can count towards the flexible reserves needed for renewable integration.

Witness Stenclik further states that DESC failed to evaluate less costly methods of integrating low-cost renewable resources. However, the Navigant Study clearly states that Witness Tanner considered the costs of adding a gas-fired peaking facility or storage to the system to provide flexible reserves for renewable integration, but excluded these options as too expensive. Tr. at 300.11. The Commission also finds that, contrary to Witness Stenclik and Witness Burgess' suggestions, the Navigant Study considered the option for new solar resources to include on-site flexibility, but this option would require existing QF contracts to be modified to provide the needed flexibility to the system. Tr. at 300.12. As to Witness Stenclik and SCSBA Witness Burgess' suggestion that DESC could implement a larger balancing area or expand reserve sharing agreements to facilitate renewable integration, the Commission recognizes there could be some benefits from such options. *Id.* However, the Commission finds that no party presented any evidence demonstrating that such options could feasibly be implemented in the short term. In fact, in response to a request from Commissioner Ervin, DESC provided a copy of its communication with Southern Company, in which Southern Company expressly stated it did not have an interest in joining the VACAR Reserve Sharing Group. DESC Letter dated October 30, 2019. The Commission therefore recognizes that such a requirement would take multiple years of study and negotiation with surrounding utilities and states and could not be easily or quickly implemented. *Id.*

CCL/SACE Witness Stenclik also suggests that the Navigant Study is flawed because solar variability and forecast errors do not pose reliability risks to DESC. Specifically, he states that there is sufficient inertia and response from other generators across the region to respond to any drops in solar generation. Tr. 629.8. He also testifies that other grid operators have successfully integrated variable renewable energy at lower levels than those estimated by DESC through coordination with neighboring balancing areas or by implementing demand response programs and battery energy storage systems. Tr. at 629.9 – 629.10. Similarly, SCSBA Witness Burgess presented data from the California Independent System Operator (CAISO) to suggest that regulating reserve requirements have not increased as solar generation has increased. Tr. at 523.85 – 523.87. Witness Tanner stated, however, that as a utility that operates a Balancing Area, DESC must maintain resource sufficiency as a standard operating procedure and a reliability requirement.

Tr. at 300.14. The Commission recognizes that utilities cannot unilaterally shift their reliability requirements onto their neighbors and finds that it would be inappropriate and not standard procedure to require the Company to rely on the broader power system for reliability without formal agreements in place. Witness Tanner also testified that Witness Stenclik's and Witness Burgess' suggestions conflate regulating reserves with flexible or operating reserves. *Id.* In this regard, the Commission finds that, while solar may not significantly have impacted the need for regulating reserves, the flexible reserve requirement forecasted in the VIC study is for resources that can respond to unexpected undergeneration from solar.

SCSBA Witness Burgess also questioned the Navigant Study based on the assertion that DESC is not an islanded system. Specifically, he suggests that there is constant interaction between DESC's balancing areas and those surrounding it. Tr. at 523.67. Accordingly, he suggests that there is frequently unscheduled flow back and forth between different areas and that any imbalance on DESC's systems could be addressed by the overall grid's frequency. Tr. at 523.70. However, the Commission finds that it would be entirely inappropriate for DESC to assume that surrounding utilities will have available resources ready to support DESC's Balancing Area, should a reliability event occur due to solar intermittency. Furthermore, the Commission recognizes that these trades between systems are economic in nature, and do not indicate that other utilities are taking responsibility to ensure that DESC has the resources needed to support reliability on its system. Tr. at 300.15. The Commission therefore finds that these exchanges of power are a separate issue from the resource availability assumptions in a reliability planning study and it would be inappropriate to rely upon such exchanges for system reliability.

Witness Burgess also asserts that the Navigant Study did not properly consider geographic diversity. In particular, he expresses a concern that the model did not appropriately account for the reduction in forecasting error and volatility of solar generation that will come from an increasing solar fleet. Tr. at 523.72. The record reflects, however, that the study examined four projects spread as widely as possible across the DESC service territory so as to reduce volatility in the weather that drives solar generation. Tr. at 300.16 – 300.17. In addition, the Commission recognizes that there is a material limit to the ability for geographic diversity to reduce overall generation variability of the solar fleet due to the small size of DESC's service territory. *Id.* The Commission therefore disagrees with Witness Burgess' criticisms and finds that the Navigant Study properly considered geographic diversity as well as volatility.

C. Form Contracts

1. Standard Offer

As stated previously, Act No. 62 requires electric utilities to establish Standard Offer contracts in order to implement the requirements of S.C. Code Ann. § 58-41-20(A). As defined by S.C. Code Ann. § 58-41-10(15), a "standard offer" consists of "the avoided cost rates, power purchase agreement, and terms and conditions approved by the Commission and applicable to purchases of energy and capacity by electrical utilities … from small power producers up to 2 MW in size." In this regard, Company Witness Kassis testified that PURPA requires utilities to have in place standard rates for QFs up to 100 kw-AC, and Act No. 62 increases this threshold to require standardized rates, terms, and conditions for QFs up to 2 MW-AC in size. Tr. at 59.17. In order to satisfy the requirements of Act No. 62 in this regard, DESC proposed a Standard Offer for the Commission's consideration. Witness Kassis testified that the proposed Standard Offer is very similar to the Form PPA proposed by the Company in that both are largely based upon the form PPA that DESC previously has used for similar utility-scaled projects. Tr. at 59.18. He also stated that it is important to include similar terms and protections for DESC's customers. *Id.*

Witness Kassis did, however, identify certain terms and conditions in the Standard Offer that differed from the previous PPA contracts used by the Company and from the Form PPA proposed by the Company in this proceeding. For example, Witness Kassis testified that the VIC clause was removed from the Standard Offer because the avoided cost methodology proposed by the Commission in this proceeding for future QF projects will directly incorporate the integration costs associated with non-variable, solar QF energy. *Id.* He also testified that the proposed Standard Offer does not contain a "seller buy down" provision as does its proposed Form PPA because it is not necessary given the other customer protections included in the Standard Offer. Tr. at 59.19. He also stated that DESC does not anticipate the need to file the Standard Offer contracts with the Commission in that it will not disclose confidential or market sensitive information. *Id.* Accordingly, DESC's proposed Standard Offer includes the mutual acknowledgement of the QF and DESC that the Standard Offer will be filed with the Commission in unredacted form. *Id.*

Witness Kassis also expressed concern that QF developers may attempt to take advantage of the Standard Offer and flood DESC with projects no larger than 2 MW-AC and that the total aggregate MW-AC of power purchased by DESC under the Standard Offer could be very significant. *Id.* He also stated that a developer could attempt to split a project into multiple smaller projects to take advantage of the Standard Offer. Tr. at 59.20. In order to address this concern, DESC proposes that the Standard Offer not be made available to a QF owned by a seller or an affiliate or partner of a seller, who sells power to DESC from another QF, using a renewable energy resource within one mile of each other, unless the aggregate capacity of the QFs is equal to or less than 2 MW-AC. *Id.* Witness Kassis testified that such a limitation would be similar to PURPA's "one-mile rule." *Id.*

As an initial matter, the Commission recognizes that certain parties disputed DESC's proposed avoided cost rates, which are reflected in the Standard Offer as proposed by the Company. The Commission has previously addressed herein the issues pertaining to avoided costs and determined that the avoided costs set forth in DESC's proposed Standard Offer are reasonable and appropriate. Accordingly, the Commission incorporates herein by reference those same findings.

With respect to the terms and conditions of the Standard Offer, ORS Witness Horii testified that the Standard Offer generally is commercially reasonable and conforms to industry standards. Tr. at 695.47. However, he identified a concern with the lack of clarity in section 6.1(a) of the Standard Offer as proposed by DESC. *Id.* Specifically, he expressed concern about what would constitute an acceptable "expected range of certainty" regarding forecasted energy production, or what a QF with no historical operating experience would provide in this regard. Tr. at 695.48. In response, Company Witness Kassis agreed with ORS's recommendations and removed the identified sentence from both the Standard Offer and the Form PPA. Tr. at 66.5 – 66.6. DESC also corrected certain errors in the Standard Offer and Form PPA that were identified by ORS. Tr. at 66.6. The Commission finds that these changes are reasonable and should be incorporated into the Standard Offer as proposed by ORS and agreed to by DESC.

On behalf of SCSBA, Witness Levitas made several references to a standard of "commercial reasonableness" which he suggested required striking a balance between promoting QF development and protecting ratepayer interests. Specifically, he stated that contract terms which make it difficult to finance QF development do not strike that balance. Tr. at 451.8. In this regard, Witness Levitas proposed to include a definition of "commercial reasonableness" in the Standard Offer and the Form PPA. *Id.* Company Witness Kassis testified, however, that SCSBA's proposed definition solely refers to what may constitute reasonableness in the mind of the "promisor" without any reference to the perspective or unique obligations that may be placed upon the counterparty under the agreement who is affected by the promisor's efforts. Tr. at 66.15. He further stated that the proposed definition contains vague language that would be incredibly difficult, if not impossible, to follow. Tr. at 66.16. After considering these issues, the Commission finds that Witness Levitas' proposed language regarding commercial reasonableness is inappropriate for inclusion in the Standard Offer and the Form PPA. Specifically, the Commission finds that attempting to define the term "commercial reasonableness" in this context likely would exacerbate disputes between QFs and DESC over the meaning of the language.

Witness Levitas also objected to language in the Standard Offer that would provide relief for liquidated damages only for interconnecting utility delays pertaining to the construction of required interconnection facilities that do not include network upgrades. Tr. at 451.13. DESC agreed with this concern and revised its Standard Offer and Form PPA by modifying the definition of "Excusable Delay" and adding a definition of "Network Upgrades." Tr. at 66.19. Witness Levitas also questioned the inclusion of language that would allow DESC to approve the Seller's engineering, procurement, and construction contracts and operation and maintenance contracts. Tr. at 451.19. Although Company Witness Kassis testified that DESC included these provisions to mitigate adverse operating conditions, he stated that the Company is willing to strike the provisions of Section 4.1(b) and has done so in its revised Form PPA and Standard Offer. Tr. at 66.24 – 66.25. The Commission finds that these changes are reasonable and should be incorporated into the Standard Offer as proposed by SCSBA and agreed to by DESC.

Witness Levitas also proposed to reduce the "Guaranteed Energy Production" requirements from 85% to 70% of the scheduled expected amount on the basis that Duke Energy uses a 70%

threshold to identify a shortfall in production. Tr. at 451.15 – 451.16. Similarly, Witness Levitas asserts that it would be unreasonable to allow DESC to terminate the Standard Offer or the Form PPA for energy shortfalls. Tr. at 451.22. Witness Kassis testified, however, that under the Standard Offer and Form PPA, the QF will operate at and maintain an expected performance of 95%. Tr. at 66.20. While the QF is obligating itself to operate and maintain performance of 95%, DESC provides QFs with additional flexibility such that if the QF simply achieves 85%, it can avoid penalties for the shortfall. *Id.* He further testified that compliance with this provision is largely within the control of the QF because the inability of a solar generating facility to satisfactorily perform typically results from either design flaws, equipment issues, or maintenance-related failures. Tr. at 66.21. Witness Kassis also testified that a non-performing QF can invest in design, equipment, and maintenance to substantially mitigate these risks in order to fulfill its contractual obligations. *Id.* Witness Kassis further testified that it is appropriate for DESC to have the right to terminate the agreement for energy shortfalls occurring in two consecutive years, rather than relying on liquidated damages or other remedies, because such QFs essentially would be neglecting the asset and another facility should have the opportunity to take advantage of providing the resource. Tr. at 118. Based upon this testimony and the record, the Commission finds that the QF is in the best position to address flaws and failures to satisfactorily perform under the Standard Offer contract and that, unless a plant has major flaws, QF facilities typically operate at or above 85%. In addition, the Commission recognizes that DESC must include these generating assets in its resource plan and therefore must rely upon the QFs to meet their obligation so that the Company can continue to provide safe and reliable service to its customers. *Id.* For these reasons, the Commission therefore finds that Witness Levitas' proposal in this regard would be inappropriate and declines to adopt the same.

In sum, the Commission finds that DESC's proposed Standard Offer form, with the modifications discussed above, are reasonable and appropriate, satisfy the requirements of Act No. 62, and therefore are hereby approved.

2. Contract Power Purchase Agreements

Act No. 62 also requires the Commission to approve a form contract PPA reflecting "an agreement between an electrical utility and a small power producer for the purchase and sale of energy, capacity, and ancillary services from the small power producer's qualifying small power production facility." S.C. Code Ann. §§ 58-41-10(9), -20(A). In proposing a Form PPA for the Commission's consideration in this proceeding, Company Witness Kassis testified that DESC believes that keeping its Form PPA largely consistent with the existing form makes sense from a business perspective because many in the renewable energy industry have either (i) executed a contract very similar to the Form PPA or (ii) become familiar with at least some iteration of this general form of PPA over the last several years. Tr. at 59.11. He also testified this concept makes sense from a regulatory perspective because these executed PPAs have all been filed with and accepted by the Commission. *Id.*

However, Witness Kassis did testify that the Company had made several modifications to tailor the Form PPA to the requirements of Act No. 62. For example, he stated that the Form PPA is no longer specific to any one type of renewable fuel source, but it is designed to accommodate any eligible renewable source, subject to some additional project-specific details. Tr. at 59.12. He also testified that DESC added a section regarding Development Period Credit Support, which is a form of security posted by the QF to secure its obligations prior to commercial operation, is common in commercial agreements, and provides security to utility customers. *Id.* The Form PPA also includes a provision regarding Excusable Delays, which generally represent delays in the ability of a QF to begin delivery of power to DESC due to (i) Force Majeure, (ii) a delay caused by DESC, or (ii) delays in the completion of the Interconnection Facilities unless such delay was directly or indirectly caused by the QF. *Id.* He testified that, if these limits are exceeded, the QF would have to pay to extend the deadline in order to maintain a viable PPA, and that these limits properly reflect the risk assumed by the QF and are appropriate with a longer 24-month development period. *Id.* Witness Kassis also testified that the Form PPA limits curtailments to Emergency Conditions and events of Force Majeure. Tr. at 59.13.

Regarding Renewable Energy Certificates ("RECs"), Witness Kassis testified that the existing PPA typically provided for a right of first offer, but that the negotiation of RECs is outside the scope of PURPA. *Id.* Witness Kassis therefore testified that RECs are not addressed in the Form PPA, but will be handled on a case-by-case basis. *Id.* As stated previously, Witness Kassis stated that the Form PPA also does not include a VIC clause because variable integration costs will be addressed in the proposed avoided cost methodology for future PPAs. Tr. at 59.14. Witness Kassis further testified that future Form PPAs will be filed in redacted form to protect certain market sensitive information including, but not limited to, avoided cost rates specific to the PPA. *Id.* Accordingly, the Form PPA was revised to reflect the protection of confidential or market sensitive information. *Id.* Finally, Witness Kassis testified that S.C. Code Ann. § 58-41-20(A) requires PPAs to address choice of venue and, therefore, the Form PPA specifies that venue shall be Columbia, South Carolina for any state or federal disputes that may arise. Tr. at 59.15.

As for criticisms of the Form PPA raised by other parties, the Commission first recognizes that certain of these challenges also pertain to provisions of the Form PPA that are similar or identical to provisions in DESC's proposed Standard Offer. In this regard, the Commission incorporates herein by reference those same findings as they may apply to the Form PPA.[16]

With respect to the terms and conditions of the proposed Form PPA, ORS Witness Horii testified that the Form PPA contains terms and conditions consistent with PURPA and FERC implementation guidelines and satisfies the requirement of Act No. 62 that the Form PPA have a 10-year term option. Tr. at 695.49.

JDA Witness Chilton did not identify any specific criticisms of the Form PPA, but generally averred that PURPA and Act No. 62 require QF generation to be allowed to compete on even terms with the utility's other generation resources. Tr. at 462.4. She also suggested that PURPA and Act No. 62 implicitly require that the QF be able to obtain regularly available, market-rate financing for the costs of developing, building, and operating their projects, which she stated requires the Commission to consider the types of financing available to QFs. *Id.* Witness Chilton further testified that, generally, the tenor for PPA contracts should be set at a minimum of 15 years, and in some cases 20 years or longer, to facilitate the opportunity to obtain financing for a majority of QFs in South Carolina. Tr. at 462.10. However, Witness Chilton testified that it is not possible to know whether costs to the ratepayers will go up or down. Tr. p. 468. Witness Kassis testified in response that PURPA and Act No. 62 do not require parity between QFs and utilities in financing, but instead seek to protect ratepayers. Tr. at 66.10. He also stated that FERC has observed that QFs, which have the advantage of mandatory purchase requirements, should be better positioned that non-QFs to negotiate contractual arrangements for financing and concluded that there will still be sufficient financing options for QFs. Tr. at 66.11. Witness Raftery further testified that the Company has signed contracts with ten-year terms reflecting that these QFs have been able to

[16] To the extent that issues pertaining to the Form PPA also relate to similar provisions in the Standard Offer, the Commission makes these same findings with respect to the Standard Offer.

access adequate financing under this length of contract. Tr. at 123. In reviewing this issue, the Commission finds that DESC's proposed 10-year term for the Form PPA and the Standard Offer is reasonable and appropriate for adoption in this proceeding. First, Act No. 62 mandates that electrical utilities offer to enter into PPAs with small power producers for a duration of ten years. S.C. Code Ann. § 58-41-20(F)(1). That reflects the General Assembly's recognition that such a tenor is reasonable. Furthermore, the Commission is not persuaded that PURPA and Act No. 62 were intended to ensure the financial feasibility of QF projects. To the contrary, FERC has recognized that it is appropriate to reduce contract lengths to mitigate the impermissible trend of avoided cost rates exceeding incremental costs. Tr. at 66.15. The Commission therefore declines to require DESC to offer the Form PPA and Standard Offer with a tenor longer than 10 years.

On behalf of SCSBA, Witness Levitas criticized the proposed Form PPA stating that it does not include appropriate terms and conditions for energy storage devices coupled with QF generation. Tr. at 451.17. In particular, he identified Act No. 62's requirement that the avoided cost methodology must fairly account for QF projects utilizing energy storage equipment and directing the Commission to consider tariffs for energy storage. Tr. at 451.17 – 451.18. Witness Kassis testified, however, that in the Settlement Agreement filed in Docket No. 2017-370-E on November 30, 2018 (the "Settlement"), DESC agreed to file with the Commission for its approval either "proposed avoided cost rates for energy and capacity that provide accurate pricing for storage as a separate resource; or proposed technology-neutral avoided cost rates for energy and capacity that provide accurate pricing for dispatchable renewable generating facilities such as solar + storage (e.g., hourly pricing)." Tr. at 66.23. He also testified that Act No. 62 states, "[t]he provisions of Section 58-41-20 shall not be interpreted to supersede the conditions of any settlement entered into by an electrical utility and filed with the commission prior to the adoption of this act." DESC plans to meet its obligation under the Settlement by making a filing with the Commission on or before December 31, 2019. *Id.* Finally, it should be noted that Act No. 62 requires each utility's avoided cost methodology account for energy storage, but it does not expressly address, much less mandate, terms and conditions.

After considering this issue, the Commission finds that Witness Levitas' suggestions are neither warranted nor required by Act No. 62. DESC has contractually agreed through the Settlement to propose avoided cost rates for energy and capacity for storage as a separate resource and the Commission has no reason to believe that the Company will not abide by its obligations in this regard. Furthermore, the record reflects that currently there are no solar QF projects that include storage and are seeking to interconnect with DESC's system at this time. Even so, Act No. 62 clearly provides that, if a QF is dissatisfied with the avoided costs calculated by DESC using the approved methodology, the QF has right to have those disputed issues resolved by the Commission in a formal complaint proceeding. S.C. Code Ann. § 58-41-20(C). The Commission therefore finds that SCSBA's recommendation in this regard is unnecessary and declines to adopt the same.

Witness Levitas also suggested a number of changes to the Form PPA for the purported purpose of reflecting "commercial reasonableness." For example, he suggested that the environmental risks for certain hazardous projects found near the QF projects should be shifted to DESC and its customers. Tr. at 451.22. The Commission finds this suggestion unreasonable, however. In these situations, the QF controls site selection, not DESC, and it would be inappropriate to shift these risks onto DESC and its customers when QFs are in the best position to mitigate or evaluate such risks. Tr. at 66.27. Witness Levitas also suggested that DESC should approve a surety bond form as an exhibit to the Form PPA and Standard Offer. Tr. at 451.22.

DESC agreed to this recommendation and the Commission finds that this recommendation of SCSBA, as agreed to by the Company, should be approved. Tr. at 66.27 – 66.28. Witness Levitas further criticized the language in Section 5.1(e) of the Form PPA alleging that this provision, which allows DESC to curtail energy under Emergency Conditions, was too vague. Tr. at 451.22 – 451.23. However, the Commission finds that Witness Levitas' suggestion relates only to directives of DESC Transmission pursuant to applicable agreements for generator and interconnection and transmission service. Tr. at 66.28. Accordingly, the Commission finds that this section focuses on directives pursuant to applicable terms within an executed interconnection agreement rather than curtailment pursuant to the provisions of the Standard Offer or the Form PPA. The Commission therefore declines to adopt SCSBA's proposed language in this regard.

Witness Levitas also suggested edits to Section 5.2(e) and (f) regarding the Seller's indemnification of the Buyer for Environmental Liability and personal energy and property damage. Tr. at 451.22 – 451.23. Again, the Commission finds that these suggestions improperly attempt to allocate risk between the QF and DESC and that the QF is best suited to recognize and mitigate these types of risk. However, DESC agreed to add language that would provide the Buyer shall indemnify the Seller against losses resulting from gross negligence or intentional misconduct of its officers. Tr. at 66.28 – 66.29. The Commission finds that this language is reasonable and should be included in the Form PPA and Standard Offer as suggested by SCSBA and agreed to by DESC. Witness Levitas further stated that language regarding termination of the Form PPA if a milestone is not achieved should not be permitted if the failure to meet a milestone does not affect the Seller's ability to achieve the Completion Date. Tr. at 451.23. Witness Kassis stated, however that this language aligns with FERC precedent on similar issues. Tr. at 66.29. The Commission finds that Witness Levitas' suggestion should not be adopted. The Form PPA provides QFs with the possibility to extend the 30-day cure period if it gives advance notice to DESC and fulfills certain other conditions. *Id.* The Commission therefore finds that giving QFs an additional extension option with no advance notice is unreasonable.

Regarding Force Majeure, Witness Levitas states that there is no extension of force majeure relief where the problem cannot be corrected in the defined time period but could be remedied with an extension. Tr. at 451.23. The Commission finds, however, that an amendment to the Form PPA to address this concern is not necessary because termination under this provision does not arise until the Force Majeure has existed for at least 8 months, which is a sufficient period of time. Tr. at 66.30. Even so, DESC revised this provision to include a 6-month period of Force Majeure that may be extended to 9 months under certain conditions. *Id.* The Commission finds that the language proposed by DESC addresses Witness Levitas' concerns and strikes an appropriate balance on this issue and, therefore, approves the revision. Witness Levitas also recommended the deletion of Section 11.6 which acknowledges that damages provided for in the event of a default are reasonable damages. Tr. at 451.23. After considering this issue, the Commission finds that the identified language would ensure the enforceability of the agreement and does not find it necessary to delete the section as suggested. Tr at 66.30.

Regarding Section 12.2 of the PPA, Witness Levitas states that the language should be revised to require the Indemnified Party to pay for its own counsel if it chooses to be separately represented. Tr. at 451.23. Witness Kassis testified, however, that this would result in an unbalanced risk allocation. Tr. at 66.31. The Commission agrees with DESC and finds that it would be inappropriate to sever the obligation to pay for expenses related to the claims simply because the Indemnified Party may seek to take advantage of additional defenses. *Id.* Witness Levitas also questioned Section 15.1 and its requirement that the Buyer must give prior written consent for the

Seller to pledge the agreement or associated revenues to a Financing Party. Tr. at 451.24. Witness Kassis testified, however, that this suggestion would eliminate DESC's ability to mitigate potential risk exposure related to pledges, encumbrances, and collateral assignments. Tr. at 66.32. The Commission finds that DESC's position is reasonable and finds that this provision appropriately provides transparency regarding direct and upstream owners of QFs, particularly in the instance of a foreclosure. *Id.*

Witness Levitas further asserts that Section 15.13 and its requirement that the Seller must repair the Facility within 8 months if damaged by weather or other unusual events is unreasonable. Tr. at 451.24. However, the Commission finds that this section contemplates only those events for which the QF would likely be compensated via applicable insurance policies and is appropriate because it mitigates DESC's risk exposure inherent in its resource planning. Tr. at 66.32 – 66.33. Regarding Section 15.14 of the Form PPA, Witness Levitas suggests that current and prospective investors and prospective purchasers should be added to the list of parties with whom confidential information can be shared and that the Agreement should not be confidential. Tr. at 451.24. Witness Kassis stated that DESC was willing to add prospective investors and purchasers of the facility provided that the QF provides the names of these parties prior to sharing the information. Tr. at 66.33. The Commission finds that this revision, as agreed to by DESC, is reasonable and allows the Company to be aware of the potential for abuse.

Regarding Section 15.16, Witness Levitas states that it is unreasonable to require a Seller to coordinate with the Buyer when making public announcements about the construction of the facility and to obtain the Buyer's approval of any publicity materials. Tr. at 451.24. The Commission disagrees and finds that it is reasonable for QFs to coordinate with DESC on public announcements so that DESC can protect itself in situations where rejection of a proposed announcement would not be unreasonable due to the nature of its content, whatever that may be. Tr. at 66.33 – 66.34. Finally, Witness Levitas suggests the inclusion of a termination right by the QF in the event "interconnection facilities and network upgrades required for the facility to be interconnected . . . exceeds $75,000 per MW or project nameplate capacity." Tr. at 451.25. Witness Kassis stated that DESC's current business practice is to work with QFs individually to develop a similar arrangement apart from these agreements on a case-by-case basis. Tr. at 66.34. Even so, Witness Kassis stated that the recommended amount was in the range DESC has used previously and therefore agreed to this recommendation in the Form PPA and Standard Offer. *Id.* The Commission finds that this provision, as suggested by SCSBA and agreed to by DESC is reasonable, but recognizes that DESC may be required to seek adjustments to this language at some point in the future to reflect current market practice.

In sum, the Commission finds that DESC's proposed Form PPA, with the modifications discussed above, are reasonable and appropriate, satisfy the requirements of Act No. 62, and therefore are hereby approved.

3. Commitment to Sell Forms

Act No. 62 also requires DESC to propose a commitment to sell form. Specifically, S.C. Code Ann. § 58-41-20(D) provides that "[a] small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility." In this regard, Company Witness Kassis stated that this provision is comparable to PURPA's legally enforceable obligation ("LEO") requirement that guards against the possibility of utilities refusing to enter into PPAs with QFs, thereby not providing them with access to the marketplace. Tr. at 59.21 – 59.22. He stated that, in contrast, a QF can submit the

NOC Form without ever attempting to negotiate any PPA with DESC. *Id.* However, he stated that, common to both the LEO concept and the NOC Form is that the QF must make a substantial commitment to sell the electrical output of its facility to the utility in order to establish this non-contractual, yet binding, commitment. Tr. at 59.22.

In satisfaction of this requirement, DESC proposed a NOC Form, which Witness Kassis stated draws largely upon LEO concepts in place in other states, as well as DESC's institutional knowledge accumulated from experience in this arena. *Id.* He testified that the NOC Form is built around the foundational principle that the QF must make a substantial commitment to delivering the electrical output of its facility before it can establish the type of non-contractual, yet binding, relationship contemplated by the NOC Form. Tr. at 59.23. He also stated that the NOC Form touches upon issues such as site control, delivery periods, and delivery deadlines as these provisions evidence substantial commitment and are important to prevent a developer from gaming the system by locking-in rates for a speculative project, which would be detrimental to ratepayers and the solar industry as a whole. *Id.*

On behalf of ORS, Witness Horii stated that the Company's proposed NOC form generally complied with PURPA and FERC implementation guidelines. Tr. at 695.45. However, he stated that there is a lack of clarity in clause 8(iii) governing automatic terminations of the NOC Form. Tr. at 695.46. Specifically, he stated that it is unclear which entity (the QF or DESC) is responsible for installing additional facilities to establish adequate interconnection facilities, and whether the QF is eligible for any payments or damages due to delays. *Id.* In response, Witness Kassis testified that DESC revised the NOC Form to expressly state that no damages will be imposed on either party as a result of DESC having insufficient interconnection facilities. Tr. at 66.5. The

Commission finds that these changes are reasonable and should be incorporated into the NOC Form as proposed by ORS and agreed to by DESC.

On behalf of SCSBA, Witness Levitas testified that it is not commercially reasonable for a QF who submits an executed NOC Form but fails to execute a PPA in a timely fashion to not be eligible for fixed pricing for a period of two years. Tr. at 451.27. However, Company Witness Kassis stated that the purpose of this provision was to reduce the potential for gaming the system by QFs. Specifically, he stated that a QF must make a binding commitment to sell its output to the utility at a defined price to establish a LEO and that the NOC Form provision is intended to deter QFs from establishing a LEO and then refusing to perform if they can lock in a LEO at a later date at higher avoided cost rates. Tr. at 66.36. The Commission agrees with the Company and finds that this provision of the NOC Form is reasonable. If a QF executes a NOC Form, the Commission finds that they should not be permitted to withdraw from the agreement without penalty and that the language proposed by DESC would guard against this issue and would protect ratepayers from paying unnecessarily higher avoided costs.

Based upon these findings and the agreed upon revisions to the NOC Form, the Commission therefore finds that the NOC Form is reasonable and satisfies the requirements of Act No. 62. Specifically, the NOC Form appropriately provides small power producers a reasonable period of time from its submittal of the NOC Form to execute a PPA. Further, the NOC Form does not require, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, that a small power producer execute a PPA prior to receipt of a final interconnection agreement from the electrical utility. Accordingly, the Commission finds that the NOC Form, as modified in accordance with the discussions herein above, should be approved.

D. Other Terms and Conditions

Pursuant to Act No. 62, the Commission is authorized to approve other terms and conditions as may be required to implement the requirements of S.C. Code Ann. § 58-41-20. No party identified or proposed any other term or condition related to this matter, other than those previously discussed herein. The Commission therefore finds that no other terms and conditions currently are required with respect to the implementation of S.C. Code Ann. § 58-41-20. In making this finding, however, the Commission does not intend to preclude or prevent the parties of record or other interested persons from requesting in future proceedings under S.C. Code Ann. § 58-41-20 the approval of other terms and conditions as may be necessary.

E. Updates to NEM Methodology

As discussed previously, the Commission determined in Docket No. 2019-2-E that issues related to avoided costs, variable integration costs, and the NEM methodology should be bifurcated from consideration in Docket No. 2019-2-E and would be addressed in a later, appropriate hearing. Order No. 2019-229 at 1; Order No. 2019-43-H at 1. The Commission also determined that DESC's then-current avoided cost rates and NEM values were to remain the same as those in effect at the time the issues were bifurcated and that, after the Commission held a hearing to consider updates to these rates, these rates and values would be subject to a "true up." Order No. 2019-43-H at 1. DESC therefore asserts that it is appropriate to consider these issues in the current proceeding and proposes to update the NEM values in connection with this docket.

Company Witness Neely testified that, in Order No. 2015-194, issued in Docket No. 2014-246-E, the Commission approved the following 11 components of value for NEM Distributed Energy Resources:

Net Energy Metering Methodology
1. +/- Avoided Energy
2. +/-Energy Losses/Line Losses
3. +/- Avoided Capacity
4. +/- Ancillary Services
5. +/- T&D Capacity
6. +/- Avoided Criteria Pollutants
7. +/- Avoided CO_2 Emission Cost
8. +/- Fuel Hedge
9. +/-Utility Integration & Interconnection Costs
10. +/- Utility Administration Costs
11. +/- Environmental Costs

= Total Value of NEM Distributed Energy Resources

Tr. at 308.21.

Company Witness Neely also testified that the Company updated these components of value by calculating both the current value and the value over the IRP planning horizon. Witness Neely further provided information on DESC's evaluation of these components and its estimate of the associated values, which are as follows:

Total Value of NEM Distributed Energy Resources ($/kWh)

	Current Period ($/kWh)	10-Year Levelized ($/kWh)	Components
1	0.02671	$0.01523	Avoided Energy Costs
2	$0.00	$0.00	Avoided Capacity Costs
3	$0.00	$0.00	Ancillary Services
4	$0.00	$0.00	T & D Capacity
5	$0.00003	$0.00003	Avoided Criteria Pollutants
6	$0.00	$0.00	Avoided CO_2 Emission Cost
7	$0.00	$0.00	Fuel Hedge
8	$0.00	$0.00	Utility Integration & Interconnection Costs
9	$0.00	$0.00	Utility Administration Costs
10	$0.00089	$0.00105	Environmental Costs
11	$0.02763	$0.01631	Subtotal
12	$0.00226	$0.00133	Line Losses @ 0.9245
13	$0.02989	$0.01764	**Total Value of NEM Distributed Energy Resources**

Tr. at 308.22

ORS Witness Horii was the only other witness to address the NEM Distributed Energy Resources values. Specifically, Witness Horii recommended that the Commission approve alternative NEM values based upon his analyses of and recommendations regarding avoided energy and capacity costs and utility integration and interconnection costs, which have been addressed and discussed by the Commission above. Tr. at 695.43. For the same reasons discussed previously, the Commission finds that Witness Horii's recommendations are not appropriate for use in calculating the NEM Distributed Energy Resources values and that the methodology presented by Witness Neely is reasonable and appropriate.

Based on the evidence of record and the Commission's findings set forth previously herein, the Commission therefore finds that DESC properly evaluated the components of value for NEM Distributed Energy Resource as presented by Witness Neely. The Commission therefore finds that DESC's proposed NEM Distributed Energy Resource values are appropriate and reasonable, are in accordance with the NEM methodology approved by the Commission in Order No. 2015-194, and are hereby approved.

F. Bifurcation of Issues from 2019-2-E

Company Witness Rooks testified that, as part of the 2019-2-E fuel cost proceeding, DESC proposed to include the updated avoided costs, variable integration costs, and updates to the NEM values in its fuel costs effective with the first billing cycle of May 2019. Tr. at 432.10. As stated previously, in Order No. 2019-43-H, the Commission determined that these issues should be bifurcated from DESC's fuel cost proceeding held in April 2019. Based upon the Commission's ruling in Order No. 2019-43-H, Witness Rooks testified that DESC proposes to calculate the difference between the updated avoided costs and the NEM methodology costs proposed in the 2019-2-E proceeding and their updated values in this proceeding, and then separately account for the difference as an incremental cost adjustment. *Id.* Witness Rooks explained that the Company proposes an effective date for the rate changes as of the first billing cycle of May 2019. *Id.* He further testified that the Company also proposes to adjust its fuel costs as part of its 2020-2-E annual fuel cost review proceeding to account for these incremental costs and that the "true up" will be reflected as an adjustment to fuel rates that will go into effect with the first billing cycle of May 2020. *Id.*; tr. at 729.6.

As to variable integration costs, Witness Rooks testified that the Company proposes to true up these costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the Commission issues its order in this proceeding. Tr. at 432.10. He further stated that DESC proposes to deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs. *Id.* Witness Rooks testified that the result of this proposal would be to reduce base fuel purchased power expense for DESC electric customers. *Id.*

ORS Witness Lawyer testified that DESC's proposed implementation of the "true-up" was reasonable. Tr. at 729.6. No other party of record opposed the Company's proposal in this regard.

The Commission finds that DESC's proposal to "true up" of the avoided cost and NEM methodology costs is reasonable and appropriate. The Commission finds that, by adjusting the Company's fuel costs in this manner, customers will not experience any immediate rate impact, and these amounts will be appropriately accounted for and "trued up" as contemplated by the Commission in Order No. 2019-43-H. The Commission therefore approves DESC's proposal and authorizes the Company to account for and recover these incremental costs through an adjustment to the fuel rates to be considered in connection with Docket No. 2020-2-E. The Commission further approves DESC's proposal that this adjustment go into effect with the first billing cycle of May 2020. Regarding the "true up" of variable integration costs, the Commission also finds that the Company's proposal is a reasonable method to reimburse DESC for these costs pursuant to the contractual agreements between the Company and QFs.

G. DESC's Proposed Rate Schedules

DESC Witness Rooks sponsored the Company's proposed rate schedules and riders in this proceeding. Witness Rooks first sponsored DESC's proposed updates to Rate PR-1 to reflect the Company's proposed avoided costs for QFs that have power production capacity less than or equal to 100 kW. Tr. at 432.4. The Company's Rate PR-1 sets forth separate avoided energy and capacity costs for both solar and non-solar qualifying small power producers. *Id.* Witness Rooks also sponsored the Company's proposed updates to its NEM Rider to reflect the current components of values for NEM Distributed Energy Resources as discussed by Witness Neely and addressed by the Commission above. Tr. at 432.4 – 432.5. Next, Witness Rooks sponsored a new rate schedule, identified as Rate PR-Avoided Cost Methodology, which sets forth the Company's proposed methodology to be used in computing the avoided energy and capacity costs associated with PPAs as provided under the provisions of S.C. Code Ann. § 58-41-20 and PURPA. Tr. 432.5. Witness Rooks also sponsored the new Rate PR-Standard Offer rate schedule. Tr. at 432.6. This rate schedule incorporates DESC's proposed Standard Offer PPA, which is more fully described by Company Witness Kassis and includes the Standard Offer avoided cost rates described and calculated by Company Witness Neely. *Id.* Witness Rooks further sponsored the Company's Rate PR-Form PPA rate schedule, which includes DESC's proposed Form PPA as more fully discussed by Company Witness Kassis. Tr. at 432.6 – 432.7.

Finally, Witness Rooks testified that, as part of this proceeding, DESC is seeking to withdraw and terminate its Rate PR-2. Tr. at 432.7. Witness Rooks testified that Rate PR-2 was intended to set forth the Company's long-run avoided costs for PPAs with a term greater than one year and was available for QFs greater than 100 kW and up to 80 MW. *Id.* As discussed by Company Witnesses Raftery and Folsom, Act No. 62 now requires DESC to make available a Standard Offer contract for QFs up to 2 MW and for QFs greater than 2 MW, DESC is required to make available the Form PPA. Tr. at 432.8. Because of these new statutory requirements, Witness Rooks stated that there is no longer a need for a standard rate schedule setting forth the avoided costs for QFs greater than 100 kW and up to 80 MW in size. *Id.* He also stated that, because Rate PR-2 has been stayed since the issuance of Order No. 2019-274 in Docket No. 2019-2-E, the date of the withdrawal and termination of Rate PR-2 should be made effective as of the last billing cycle of April 2019. Tr. at 432.9.

As a general matter, several witnesses presented by the other parties of record proposed alternative avoided costs and methodologies through their testimony in this proceeding. These proposals, if approved by the Commission, consequently would require changes to the rate schedules sponsored by Company Witness Rooks. Based upon the stated findings of the Commission above, however, the Commission finds that DESC's proposed avoided costs and methodologies are appropriate and should be approved and, therefore, no changes to the rate schedules are necessary in these regards.

However, ORS Witness Lawyer made one recommendation with respect to the "Limiting Provisions" section of the Company's proposed Rate PR-1 rate schedule and suggested that DESC should add language to clarify the effects of an executed legally enforceable obligation in this section. Tr. at 729.7. Company Witness Kassis testified, however, that Witness Lawyer appeared to be referencing the submittal of an executed NOC form to DESC by a QF and, in that case, the QF must execute the Form PPA within a reasonable period of time from such submission. Tr. at 66.7. Subsequently, the Form PPA would govern the relationship between the QF and DESC and Witness Kassis therefore testified that it is not necessary to replicate the same level of detail in the NOC Form. *Id.* The Commission finds that the change proposed by ORS to Rate PR-1 is unnecessary and duplicative and therefore declines to adopt Witness Lawyer's recommendation in this regard.

Witness Lawyer also recommended a change to DESC's proposed Rate PR-Avoided Cost Methodology. Specifically, he suggested that the Commission should require the language in Section C to include the following provision: "Any updates to the factors or analysis must be approved by the Public Service Commission of South Carolina." Tr. at 729.7 – 729.8. In this regard, Witness Lawyer stated the intention was to make clear that DESC's avoided cost methodology may not be updated without prior Commission approval pursuant to S.C. Code Ann. § 58-41-20(A) of Act 62. Tr. at 729.8. In response, Witness Rooks testified that DESC did not oppose the addition of this language to the extent that the language is intended to clarify that any changes to the methodology itself would require Commission approval. However, he testified the Company would oppose this language if the intention of the language was to require DESC to come before the Commission each and every time it negotiates a PPA with a QF in order to receive approval for the underlying data used in the methodology to calculate avoided costs for each specific project. Tr. at 437.2 – 437.3. At the hearing in this matter, ORS Witness Lawyer agreed ORS's recommendation only pertained to changes to the methodology itself and not to the underlying data used in the methodology. Tr. at 733.

After reviewing the evidence of record and based upon the findings previously addressed herein, the Commission finds that Section C of Rate PR-Avoided Cost Methodology should be modified as proposed by ORS. The Commission further finds that this language shall not be interpreted to require DESC to come before the Commission each and every time it negotiates a PPA with a QF in order to receive approval for the underlying data used in the methodology to calculate avoided costs for each specific project. Rather, this language shall be interpreted to mean that DESC must receive Commission approval before making any changes to the underlying methodology itself. With that change, the Commission therefore finds that the rate schedules proposed by the Company are reasonable and appropriate, satisfy the requirements of S.C. Code Ann. § 58-41-20, are hereby approved, and shall be made effective with the first billing cycle of the month following the date of this Order. The Commission also finds that, in light of the requirements of Act No. 62, the Company's Rate PR-2 is no longer necessary or required. The Commission therefore approves the withdrawal and termination of Rate PR-2 effective as of the last billing cycle of April 2019.

H. Transparency of DESC's Proposals

Act No. 62 also provides that "[e]ach electric utility's avoided cost filing must be reasonably transparent [so that the utility's] underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." S.C. Code Ann. § 58-41-20(J). On behalf of ORS, Witness Horii testified that the Company's filings in this matter were reasonably transparent for his independent review and analysis. Tr. at 695.6. He also testified that DESC provided data responses and supporting information to its filings that allowed ORS to conduct its analysis, assess the reasonableness of the Company's proposals, and develop recommendations regarding the implementation of Act 62. *Id.* In addition, Witness Horii stated that he was able to recommend changes to the Company's assumptions and flow his changes through the Company's models to update the avoided energy and capacity rates for all QFs and the VIC for solar QFs. *Id.*

SCSBA Witness Burgess testified, however, that he did not believe the filings had been reasonably transparent and that he could not independently verify the reasonableness of DESC's proposed rates based on the information provided. Tr. at 523.22. Specifically, he referenced a meaningful lack of transparency regarding DESC's rationale for selection of peak hours and peak seasons, as well as hourly avoided cost data and marginal cost data for the base and change case in the DRR analysis. *Id.* In response, DESC Witness Neely stated that, through his direct testimony, Witness Burgess was able to accurately describe the methodology used by the Company and, therefore, appeared to understand and be aware of the methodology employed as well as its individual components and the underlying data. Tr. at 319.21.

Even though Witness Burgess stated that DESC only provided a high-level explanation of its methodologies in its direct testimony and alleged that the Company did not provide access to adequate data and modeling details, the Commission finds that the record does not support his assertions in this regard. Through his direct testimony, Witness Burgess, as well as the other parties, were able to present alternative avoided cost values and methodologies using the information provided by DESC. Although the Commission disagrees with these positions as discussed previously, the Commission finds that the parties could have only conducted this analysis through DESC's provision of background and supporting data regarding its proposals. In addition, the Commission notes that there were no outstanding motions to compel as of the date of the hearing. Although SCSBA did file a motion to compel, it ultimately elected to withdraw the motion and did not seek to have the Commission intervene into the discovery process. The record therefore reflects that parties determined that responses to their discovery demands were sufficient to further inform them about DESC's filing and to allow them to conduct their analyses. Accordingly, the Commission finds that the Company has satisfied the requirements of S.C. Code Ann. § 58-41-20(J) and that its avoided cost filing has been reasonably transparent.

VI. CONCLUSIONS OF LAW[17]

In entering its order in this proceeding, the Commission makes the following conclusions of law based upon the filings, testimony, and exhibits that were received into evidence at the hearing in this proceeding and based on the entire record of these proceedings:

[17] To the extent the following conclusions of law are findings of fact, they are so adopted.

1. The Commission has jurisdiction over this matter pursuant to Act No. 62 and S.C. Code Ann. § 58-41-20.

2. DESC is lawfully before the Commission pursuant to S.C. Code Ann. § 58-41-20 seeking approval of its calculations of avoided costs, its proposed avoided cost methodology, and its proposed Standard Offer, Form PPA, and NOC Form.

3. Act No. 62 requires the Commission to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The Commission also is required to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina which are brought about by the consequences of Act No. 62.

4. The methodologies used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer as described in the testimonies of Company Witnesses Lynch, Neely, and Bell are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and reduce the risk placed on the using and consuming public.

5. The avoided energy and capacity costs for DESC's proposed Rate PR-1 and Rate PR-Standard Offer, as shown in 1) Table 2 on page 13, 2) Table 3 on page 17, and in Table 4 on pages 20-21 of Company Witness Neely's Amended Direct Testimony are reasonable and prudent;

satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and reduce the risk placed on the using and consuming public.

6. With the modifications approved by the Commission herein, DESC's proposed Rate PR-1 and Rate PR-Standard Offer, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions are lawful, just and reasonable.

7. With the modifications approved by the Commission herein, DESC's proposed avoided cost methodology, as set forth in its Rate PR-Avoided Cost Methodology, is reasonable and prudent; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is just and reasonable; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

8. With the modifications approved by the Commission herein, DESC's proposed Form PPA, as reflected in Rate PR-Form PPA, is just and reasonable; is commercially reasonable; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

9. With the modifications approved by the Commission herein, DESC's proposed NOC Form, as reflected in Exhibit No. ___ (DFK-3) to the rebuttal testimony of Company Witness Kassis is just and reasonable; provides small power producers a reasonable period of time from its submittal of the form to execute a PPA; satisfies the requirements of PURPA, FERC's

implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

10. The updated components of value for NEM Distributed Energy Resources as shown in Table 5 on page 22 of Company Witness Neely's Amended Direct Testimony are reasonable and prudent, comply with the NEM methodology approved by the Commission in Order No. 2015-194, properly evaluate and/or quantify all categories of potential costs or benefits to DESC's system, and satisfy the requirements of S.C. Code Ann. § 58-40-10, et seq. (2015).

11. DESC's proposed revisions to its "Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities tariff sheet, including the rates, terms, and conditions, are lawful, just and reasonable.

12. DESC's calculation of and method of accounting for avoided costs and incremental costs for NEM were reasonable and prudent, were consistent with the methodology approved in Commission Order No. 2015-194, and complied with S.C. Code Ann. § 58-40-10 *et seq.* (2015).

13. Pursuant to Order No. 2019-43-H, DESC should be permitted to 1) to calculate the difference between the updated avoided costs and the NEM methodology costs proposed in the 2019-2-E proceeding and their updated values in this proceeding as of the first billing cycle of May 2019, 2) separately account for the difference as an incremental cost adjustment in its 2020-2-E annual fuel cost proceeding to account for these incremental costs, and 3) reflect this "true up" as an adjustment to fuel rates that will go into effect with the first billing cycle of May 2020.

14. Pursuant to Order No. 2019-43-H, the Company should be permitted to 1) true up variable integration costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the date of this order and 2) deduct these "trued up" costs from

future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs.

15. It is reasonable and appropriate for Rate PR-2 to be withdrawn and terminated effective as of the last billing cycle of April 2019.

VII. ORDERING PROVISIONS

IT IS THEREFORE ORDERED THAT:

1. The methodologies used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

2. The avoided energy and capacity costs for DESC's proposed Rate PR-1 listed in the table below are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours ($/kWh)	Peak Season Off-Peak Hours ($/kWh)	Off-Peak Season Peak Hours ($/kWh)	Off-Peak Season Off-Peak Hours ($/kWh)
May 2019-April 2020	0.03075	0.02566	0.03330	0.03363

PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December, January, February 6 a.m. to 9 a.m.	0.07346

PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	Year Round ($/kWh)
May 2019-April 2020	0.02763

PR-1 RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

The avoided capacity costs for solar QFs are zero.

3. The avoided energy and capacity costs for DESC's proposed Rate PR-Standard Offer listed in the table below are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/MWh)

Time Period	Peak Season Peak Hours ($/MWh)	Peak Season Off-Peak Hours ($/MWh)	Off-Peak Season Peak Hours ($/MWh)	Off-Peak Season Off-Peak Hours ($/MWh)
2020-2024	32.80	27.97	33.01	30.73
2025-2029	38.39	31.66	41.91	35.19

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/MWh)

Time Period	($/MWh)
December, January, February 6 a.m. to 9 a.m.	73.46

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/MWh)

Time Period	Annual ($/MWh)
2020-2024	16.76
2025-2029	15.66

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Solar QFs ($/MWh)

The avoided capacity costs for solar QFs are zero.

4. As modified by the Commission in this Order, Rate PR-1, Rate PR-Standard Offer, Rate PR-Avoided Cost Methodology, Rate PR-Form PPA, and the NOC Form, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

5. DESC's calculation and method of accounting for avoided and incremental costs for NEM were reasonable and prudent, were consistent with the methodology approved in Commission Order No. 2015-194, and complied with S.C. Code Ann. § 58-40-10, *et seq.*

6. The updated components of value for NEM Distributed Energy Resources listed in the table below comply with the NEM methodology approved by the Commission in Order No.

2015-194, properly evaluate and/or quantify all categories of potential costs or benefits to DESC's system and satisfy the requirements of S.C. Code Ann. § 58-40-10, *et seq.*

	Current Period ($/kWh)	**10-Year Levelized ($/kWh)**	**Components**
1	0.02671	$0.01523	Avoided Energy Costs
2	$0.00	$0.00	Avoided Capacity Costs
3	$0.00	$0.00	Ancillary Services
4	$0.00	$0.00	T & D Capacity
5	$0.00003	$0.00003	Avoided Criteria Pollutants
6	$0.00	$0.00	Avoided CO_2 Emission Cost
7	$0.00	$0.00	Fuel Hedge
8	$0.00	$0.00	Utility Integration & Interconnection Costs
9	$0.00	$0.00	Utility Administration Costs
10	$0.00089	$0.00105	Environmental Costs
11	$0.02763	$0.01631	Subtotal
12	$0.00226	$0.00133	Line Losses @ 0.9245
13	$0.02989	$0.01764	**Total Value of NEM Distributed Energy Resources**

7. DESC's proposed revisions to its "Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities tariff sheet, including the rates, terms, and conditions, are lawful, just and reasonable and are hereby approved for use on, during, and after the first billing cycle of the month following this Order.

8. DESC is authorized to 1) to calculate the difference between the updated avoided costs and the NEM methodology costs proposed in the 2019-2-E proceeding and their updated values in this proceeding as of the first billing cycle of May 2019, 2) separately account for the difference as an incremental cost adjustment in its 2020-2-E annual fuel cost proceeding to account

for these incremental costs, and 3) reflect this "true up" as an adjustment to fuel rates that will go into effect with the first billing cycle of May 2020.

9. DESC is authorized to 1) true up variable integration costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the date of this order and 2) deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs.

10. Rate PR-2 is withdrawn and terminated effective as of the last billing cycle of April 2019.

11. Within ten (10) days of receipt of this Order, DESC shall file with the Commission and serve copies on the Parties the tariff sheets and rate schedules approved by this Order, which are as follows:

a. Rate PR-1;
b. Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities;
c. Rate PR-Avoided Cost Methodology;
d. Rate PR-Standard Offer;
e. Rate PR-Form PPA

The avoided cost and other rates reflected in any such tariff sheets shall be consistent with the components and factors set forth herein. The revised tariffs should be electronically filed in a text searchable PDF format using the Commission's DMS System (https://dms.psc.sc.gov/). An additional copy should be sent via e-mail to etariff@psc.sc.gov to be included in the Commission's ETariff system (https://etariff.psc.sc.gov). DESC shall provide a reconciliation of each tariff rate change approved as a result of this order to each tariff rate revision filed in the ETariff system.

Such reconciliation shall include an explanation of any differences and be submitted separately from the Company's ETariff filing. Each tariff sheet shall contain a reference to this Order and its effective date at the bottom of each page.

12. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

____
Comer H. Randall, Chairman

ATTEST:

____
____, Vice Chairman
(SEAL)